

## Class VI UIC Project Information Tracking

This submission is for:

Project ID: R05-IN-0003

Project Name: Project Hoosier #1

Current Project Phase: Pre-Injection Prior to Construction

### General Information

Number of proposed Class VI wells: 1

Brief description of the project: One Carbon Partnership (OCP) intends to use one well located at the Cardinal Ethanol Facility to inject up to 450 thousand metric tons of supercritical CO<sub>2</sub> per year into the Mt. Simon. Monitoring wells will be utilized on Carinal property as detailed in the project narrative and testing and monitoring plans.

Underground Injection Control (UIC) Program under Safe Drinking Water Act (SDWA)

Description: Class 6 permit needed to sequester CO<sub>2</sub>

Other relevant environmental permits, including state permits

Permit Type(s) and ID: Will submit drilling permits with the state of Indiana prior to well installation. Permits for the monitoring wells and injection well will be obtained following well installation.

Optional Additional Project Information

### Facility and Owner/ Operator Information

Facility name: Cardinal Ethanol

Facility mailing address: 1554 N. 600 E. Union City, IN 47390

Facility location: Latitude: 40.186587 Longitude: -84.864284

Up to four Standard Industrial Classification (SIC) codes for the products/services provided by the facility: 2869

Facility located on Indian lands: No

Facility contact information

Contact person: Jeremy Herlyn

Contact's business phone number: 866 - 559 - 6026

Contact's business email: jeremeyherlyn@cardinalethanol.com

Operator's name: One Carbon Partnership, LP

Operator's business address: 1554 N. 600 E. Union City, IN 47390

Operator's business phone number: 866 - 559 - 6026

Operator's status: Private

Ownership status: Owner

### Initial Permit Application

Permit Application Narrative: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjInfo-07-06-2022-1413/1.--Project-Narrative\\_Template--Hoosier--1-NoCBI.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjInfo-07-06-2022-1413/1.--Project-Narrative_Template--Hoosier--1-NoCBI.pdf)

Proposed project plans, submitted with the Project Plan Submission module:

An Area of Review (AoR) and Corrective Action Plan

A Testing and Monitoring Plan

A Well Plugging Plan

A Post-Injection Site Care (PISC) and Site Closure Plan

An Emergency and Remedial Response Plan

Computational modeling information, submitted with the Area of Review Computational Modeling module

A financial responsibility demonstration, submitted with the Financial Responsibility Demonstration module

A proposed pre-operational logging and testing program, submitted with the Pre-Operational Testing module

An optional alternative PISC timeframe demonstration, submitted with the Alternative PISC Timeframe Demonstration module

### Updated Information

### Complete Submission

Authorized submission made by: Ricky Weimer

For confirmation a read-only copy of your submission will be emailed to: [craig@vault4401.com](mailto:craig@vault4401.com)

**ATTACHMENT 1: CLASS VI PERMIT APPLICATION NARRATIVE**  
**40 CFR 146.82(a)**  
**HOOSIER #1 PROJECT**



June 29, 2022

Several figures contained within this document contain Confidential Business Information (CBI) that is privileged and exempt from public disclosure – “Narrative without CBI”. These images will be delivered to the United States (US) Environmental Protection Agency (EPA) in a separate document – “Narrative with CBI”.

The figures listed below contain CBI and have been redacted from the publicly disclosed version of this document:

Figure 19: Confidential Business Information: 2D seismic lines two-way time (TWT) in a 3D view

Figure 20: Confidential Business Information: 2D surface seismic Line 1 EW

Figure 21: Confidential Business Information: 2D surface seismic Line 2 NS

Figure 22: Confidential Business Information: 2D surface seismic Line 3 short NS

Figure 31: Confidential Business Information: IN133540 input data and petrophysical analysis

Figure 32: Confidential Business Information: AK Steel input data and petrophysical analysis

Figure 33: Confidential Business Information: INEOS (BP Lima) Nitriles input data and petrophysical analysis

Plan revision number: N/A  
Plan revision date: July 4, 2022

Figure 34: Confidential Business Information: IN144601 input data and petrophysical analysis

Figure 35: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey)

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### Acronyms

2D	Two-dimensional
3D	Three-dimensional
ACZ	Above Confining Zone
ACZ1	Above Confining Zone Monitor Well
ALARP	As Low as Reasonably Possible
AoR	Area of Review
Avg	Average
CCS	Carbon Capture and Sequestration
CCS1	Proposed Injection Well
CI	Contour Interval
CO <sub>2</sub>	Carbon Dioxide
CPO	Central Plains Orogenic Province
CWA	Clean Water Act
DGS	Division of Geological Survey
DOW	Division of Water
DST	Drill Stem Test
ECRB	East Continent Rift Basin
EGRP	Eastern Granite-Rhyolite Province
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
FEMA	Federal Emergency Management Agency
Fbsl	Feet Below Sea Level
Ft	Feet
GPM	Gallons Per Minute
GP	Grenville Province
GSDT	Geologic Sequestration Data Tool
h	Thickness
IDNR	Indiana Department of Natural Resources
IEc	Industrial Economics
IGWS	Indiana Geological and Water Survey
IGS	Indiana Geological Survey
JV	Joint Venture
k	Permeability
kt	metric kilotons
LAS	Log Ascii Standard
lbs	Pounds

LCZ	Lost Circulation Zone
LEPC	Local Emergency Planning Committee
mD	Millidarcy
MMT	Million Metric Tons
MMT/ yr	Million Metric Tons per Year
MRS	Midcontinent Rift System
MSL	Mean Sea Level
NESHAPS	National Emission Standards for Hazardous Pollutants
NPDES	National Pollutant Discharge Elimination System
OBS1	Deep Observation Well
ODNR	Ohio Department of Natural Resources
OCF	One Carbon Partnership, LP
PISC	Post Injection Site Care and Site Closure
PSD	Prevention of Significant Deterioration
RA	Risk Assessment
RCRA	Resource Conservation and Recovery Act
RMP	Risk Management Plan
SDWA	Safe Drinking Water Act
SGRP/WGRP	Southern/Western Granite-Rhyolite Province
TBD	To Be Determined
TD	Total Depth
TDS	Total Dissolved Solids
TVD	True Vertical Depth
TWT	Two-way Time
UIC	Underground Injection Control
US	United States
USGS	United States Geological Survey
USDW	Underground Source of Drinking Water
USDW1	USDW monitoring well

## **1 Project Background and Contact Information [40 CFR 146.82(a)(1)]**

### **1.1 Project Contact Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
866-559-6026  
jeremeyherlyn@cardinalethanol.com

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CCS1 Injection Well Location  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

### **1.2 Project Background**

Vault 44.01 (Vault) and Cardinal Ethanol, LLC (Cardinal) have formed a joint venture (JV) to design, implement, and operate a successful commercial Class VI carbon dioxide (CO<sub>2</sub>) sequestration project. The name of this JV is One Carbon Partnership, LP (OCP). The Cardinal plant is an ethanol production facility located in Randolph County, Indiana that began operations in 2008. Vault is a multi-national Carbon Capture and Sequestration (CCS) project development company.

Cardinal produces approximately 140 million gallons of ethanol per year. This ethanol is produced from the corn fermentation process. A natural byproduct of this process is CO<sub>2</sub>. Cardinal produces approximately 420 metric kilotons (kt) of CO<sub>2</sub> per year, with an anticipated expanded volume of ethanol production that would equate to approximately 450 kt of CO<sub>2</sub> per year. The objective of this project is to sequester the full anticipated volume of up to 450 kt of CO<sub>2</sub> per year.

Cardinal will work with Vault to install a facility to capture the CO<sub>2</sub> generated by the corn fermentation process and sequester it deep underground via an injection well (CCS1). This well, the capture equipment, and all auxiliary equipment related to the project will be contained on property owned by Cardinal.

The capture portion of this project will use compressors, blowers, cooling units, and scrubbers to purify and condense the CO<sub>2</sub> into a supercritical state. This supercritical CO<sub>2</sub> will then be piped to CCS1 and injected deep into the Mt. Simon Sandstone. The Mt. Simon Sandstone is of sufficient depth and temperature at the site to maintain this supercritical state. The Mt. Simon Sandstone has served as a suitable injection interval for Class I and II wells in the region for

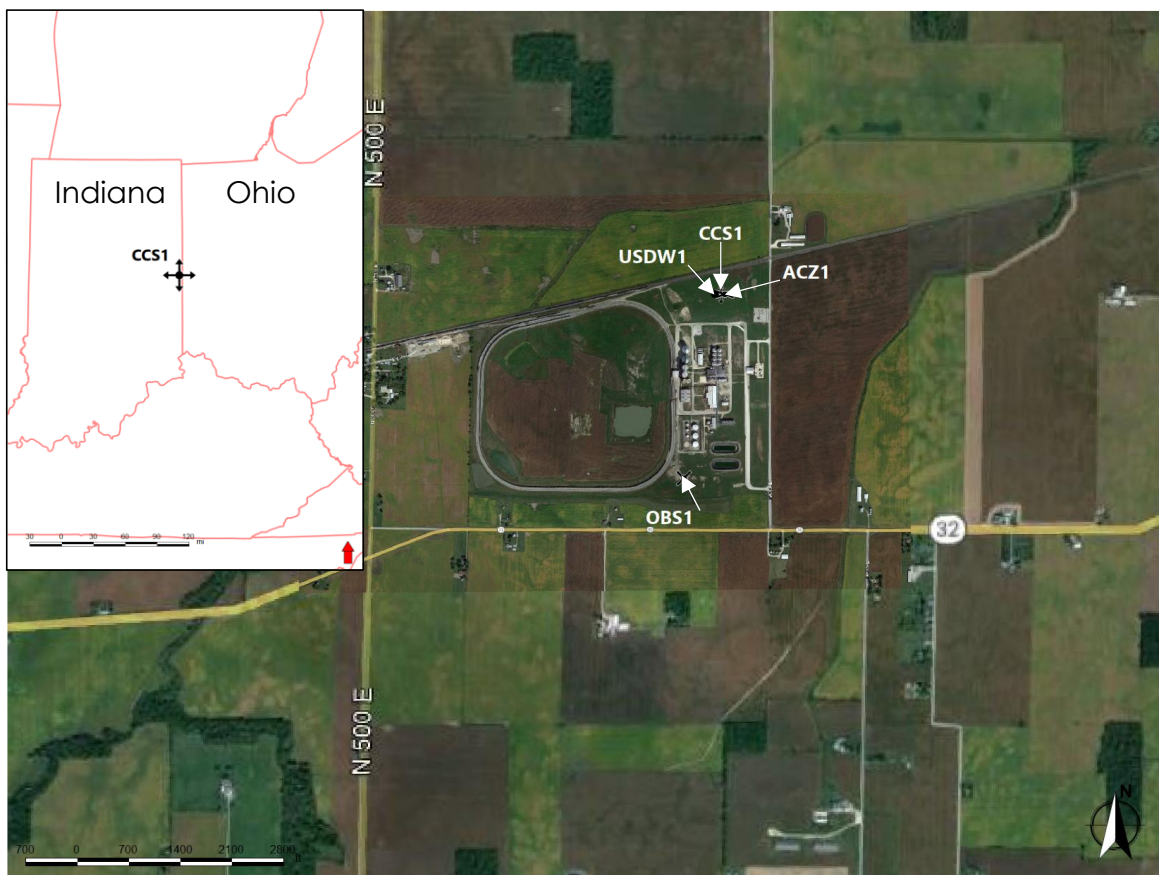
multiple decades (INEOS (BP Lima) Nitriles, August 22, 2016; AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021). The confining zone is Eau Claire Shale with the Knox Dolomite as a secondary confining zone.

The Hoosier #1 Project intends to enable OCP to continue to provide jobs and economic opportunity while minimizing the amount of CO<sub>2</sub> emitted into the earth's atmosphere. OCP maintains that both economic and environmental stewardship can advance in unison with an asset such as the Hoosier #1 Project.

Thorough analysis has been performed using publicly available data, two-dimensional (2D) seismic lines, and other data sources to confirm the feasibility of this project.

Based on the maximum anticipated annual volume of 450 kt of CO<sub>2</sub> per year over a period of 12-years (5.4 MMT of CO<sub>2</sub>) to 30-years (13.5 MMT of CO<sub>2</sub>), the total mass of injected CO<sub>2</sub> is anticipated to range from 5.4-13.5 MMT, respectively.

Figure 1 shows the locations of the four primary wells associated with the project. Table 1 shows the coordinates, depth, and information for the four primary wells associated with the project.



**Figure 1: Project and Well Location Map**

**Table 1: Proposed Hoosier #1 Project wells**

<b>Well Name</b>	<b>X (ft) EPSG 2965</b>	<b>Y (ft) EPSG 2965</b>	<b>Elevation feet below sea level (fbsl)</b>	<b>Total Depth (TVD) (ft)</b>	<b>Purpose</b>
CCS1	552167	1799966	-1100.2	3,708	CO <sub>2</sub> injection well Designed to inject 450 metric kilotons of CO <sub>2</sub> per year.
OBS1	551657	1797463	-1106.6	3,709	Injection reservoir observation well. Located 2,600 ft south of CCS1. Logging and pressure monitoring will be used to history match the CO <sub>2</sub> migration in the reservoir and ensure containment.
ACZ1	552218	1799966	-1100.1	1,666	Above confining zone (ACZ) observation well. Targeting the most permeable formation above the confining zone, this well will be used as a detection point in the event CO <sub>2</sub> migration above the confining zones.
USDW1	552080	1799966	-1100.2	600	Deepest underground source of drinking water (USDW) monitoring well. Completed in the deepest USDW, this well will be used to monitor the groundwater chemistry.

This document is one of the below 12 attachments that are being submitted to the United States US EPA for approval for a Class VI well for the Hoosier #1 Project. The other 11 attachments are listed below:

(Attachment 1: Narrative, 2022)

(Attachment 2: AoR and Corrective Action, 2022)

(Attachment 3: Financial Responsibility, 2022)

(Attachment 4: Well Construction, 2022)

(Attachment 5: Pre-Op Testing Program, 2022)

(Attachment 6: Well Operations, 2022)

(Attachment 7: Testing And Monitoring, 2022)

(Attachment 8: Well Plugging, 2022)

(Attachment 9: Post-Injection Site Care, 2022)

(Attachment 10: ERRP, 2022)

(Attachment 11: QASP, 2022)

(Attachment 12: Confidential Business Information: Risk Register, 2022)

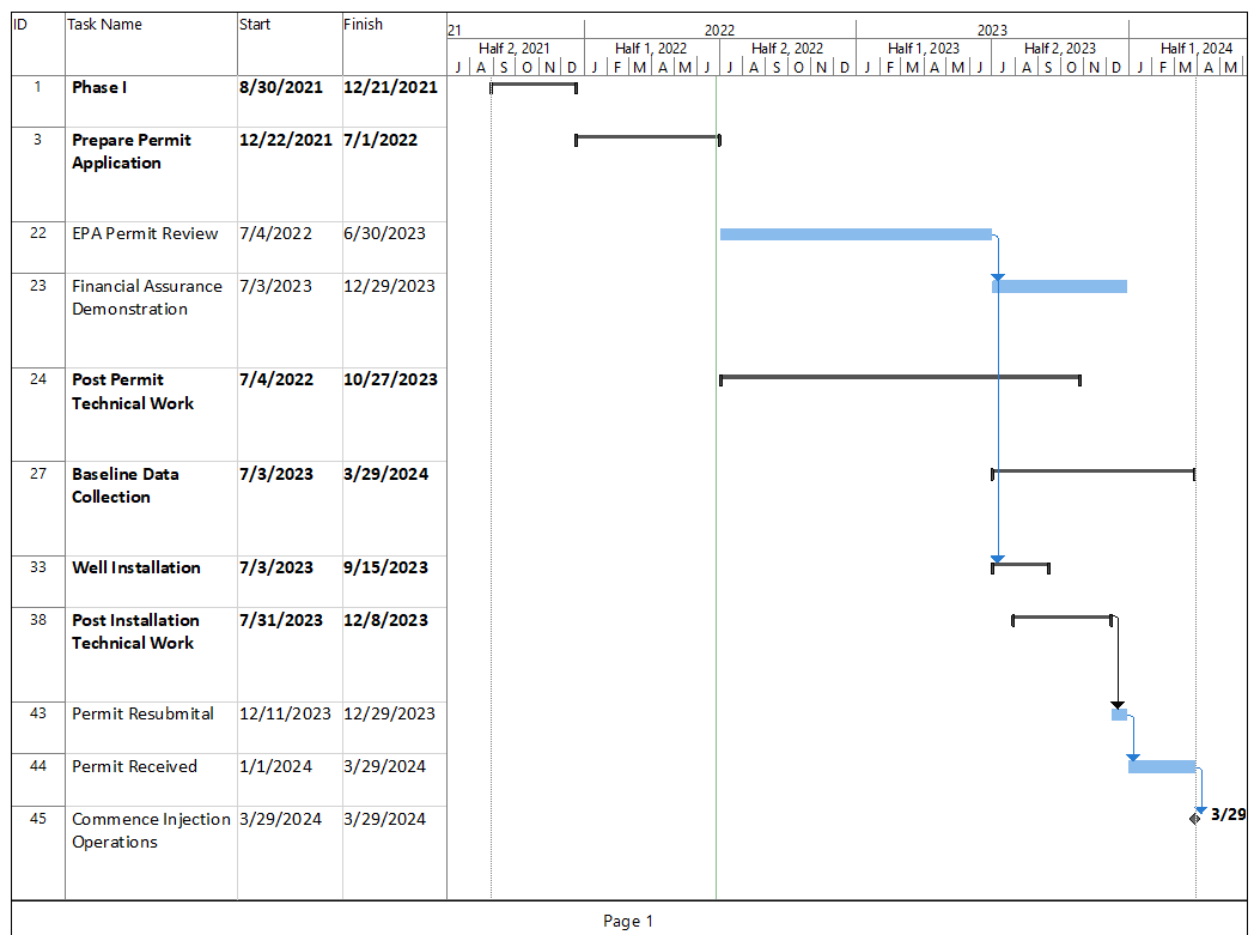
### 1.3 Project Goals

An objective of this project and Class VI application is to establish that CO<sub>2</sub> produced at the Cardinal corn processing facility can be effectively captured and permanently sequestered deep in the Mt. Simon Sandstone.

This application seeks approval to continue this effort. Upon approval, project execution will begin with the drilling and completion of several wells including the CO<sub>2</sub> injection well (Figure 1, Table 1). Real-time data will be collected as the wells are drilled and completed. The data gathered will be processed and analyzed to confirm or re-assess the project modeling efforts and current understanding. If necessary, additional data sets will be collected and analyzed.

## 1.4 Project Timeframe Overview

A projected pre-injection project schedule is shown in Figure 2.



**Figure 2: Pre-Injection Project Schedule.**

A preliminary Post Injection Site Care and Closure (PISC) schedule is shown in Figure 3.

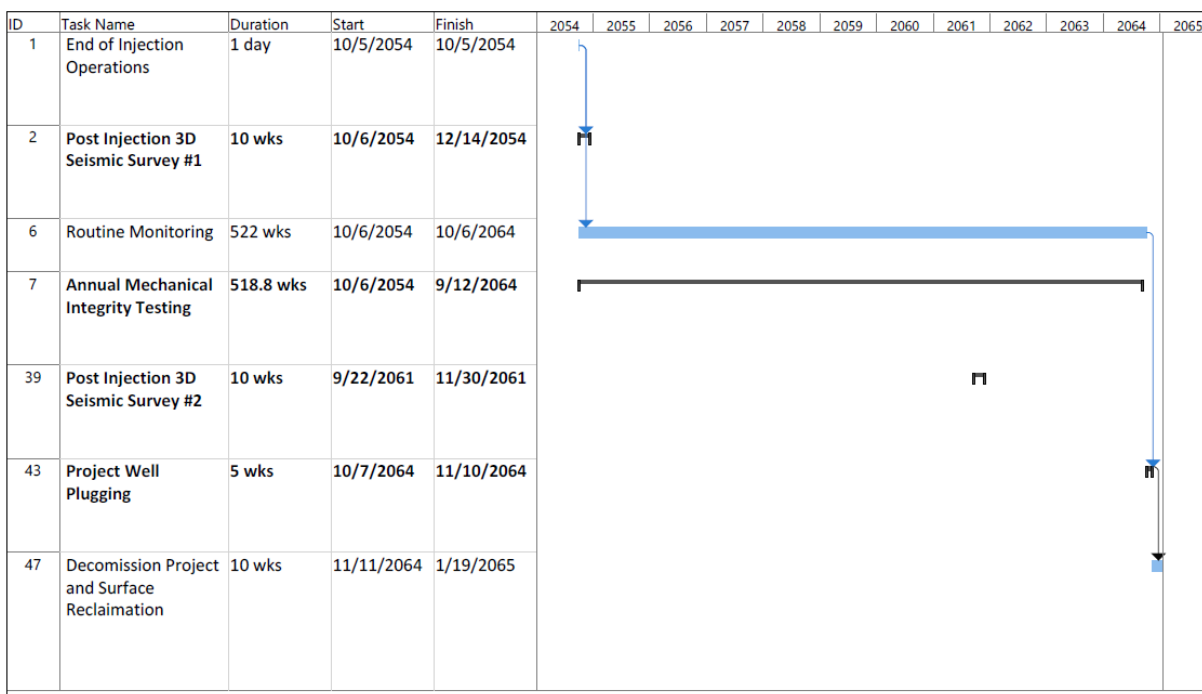


Figure 3: PISC Project Schedule

## 1.5 Partners

The Hoosier #1 Project and facilities will be jointly owned by Vault and Cardinal under the JV One Carbon Partnership, LP.

## 1.6 Proposed Injection Mass/Volume and CO<sub>2</sub> Source

It is anticipated that one injection well will be sufficient to handle the project's intended mass flow rate while maintaining maximized storage efficiency of the Mt. Simon Sandstone. The Hoosier #1 Project has been designed to operate for thirty years at a nameplate capacity per annum of 450,000 tons of CO<sub>2</sub>.

## 1.7 Local, State, and Federal Emergency Contacts [40 CFR 146.82(a)(20)]

Table 2: Local, State, and Federal Emergency Contacts

Agency	Phone Number
Union City Police Department	765-964-5353
Union City Fire & EMS	765-964-4488 (Indiana) 937-968-5605 (Ohio)
Randolph County Sheriff	765-584-1721
Indiana State Police	765-778-2121

Agency	Phone Number
Indiana Emergency Management and Preparedness Division	765-584-1721 (Local)
Environmental services contractor	516-333-4526 (Environmental Consultant-RTP Environmental Associates) 260-489-7062 (Emergency Spill Response)
Underground Injection Control (UIC) Program Director (Region 5)	312-353-7648
EPA National Response Center (24 hours)	800-424-8802
Indiana Department of Natural Resources (IDNR)	317-232-4200

## 1.8 Summary of Other Permits Required

Table 3 provides a summary of permits required for the Hoosier #1 Project.

**Table 3. Permits Required for the Hoosier #1 Project**

Program	Permits	Status
a) Hazardous Waste Management program under the Resource Conservation and Recovery Act (RCRA)	Not required	Not Applicable
b) UIC program under the Safe Drinking Water Act (SDWA)	(UIC) Class VI Permit Randolph County Cardinal CCS1	Permit Submitted to EPA Region 5
c) NPDES program under the Clean Water Act (CWA)	Not planning to be used for Class VI UIC project	Not necessary, water from well installation will not be discharged into local bodies of water
d) Prevention of Significant Deterioration (PSD) program under the Clean Air Act	Not required	Not necessary, no additional air pollution will be introduced as part of the Class VI project
e) Nonattainment program under the Clean Air Act	Not required	Not applicable. Area is in attainment for all criteria pollutants
f) National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act	Not required	Not Applicable
g) Dredge and fill permits under section 404 of the CWA	Not necessary for CO <sub>2</sub> plant and flowline(s); well pad(s) will not affect wetlands	Wetlands areas are being avoided at the power plant site and injection/monitoring well pad locations.

Plan revision number: N/A  
Plan revision date: July 4, 2022

Program	Permits	Status
h) Other relevant environmental permits, including State permits		
Drilling Permit(s)	Required for injection/monitoring wells	Application(s) to permit the wells laid out in this permit application will be submitted at a later time, prior to well installation.
Well Permit(s)	Required for injection/monitoring wells	Application(s) to permit the wells laid out in this permit application will be submitted after they are installed. Regulatory path towards permitting these wells is currently being legislated at the state level in Indiana.

## 2 Site Characterization [40 CFR 146.82(a)(2), (3), (5), and (6)]

Unless otherwise stated, all depths are in reference to feet (ft) below ground surface.

### 2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

The Hoosier #1 Project site is located on the Indiana-Ohio Platform/Arches Province that is a high region between the Illinois, Appalachian, and Michigan Basins (Figure 4). Structural relief on the Indiana-Ohio Platform is generally the result of differential subsidence of the surrounding basins as opposed to tectonic uplift (Drahovzal, et al, 1992).

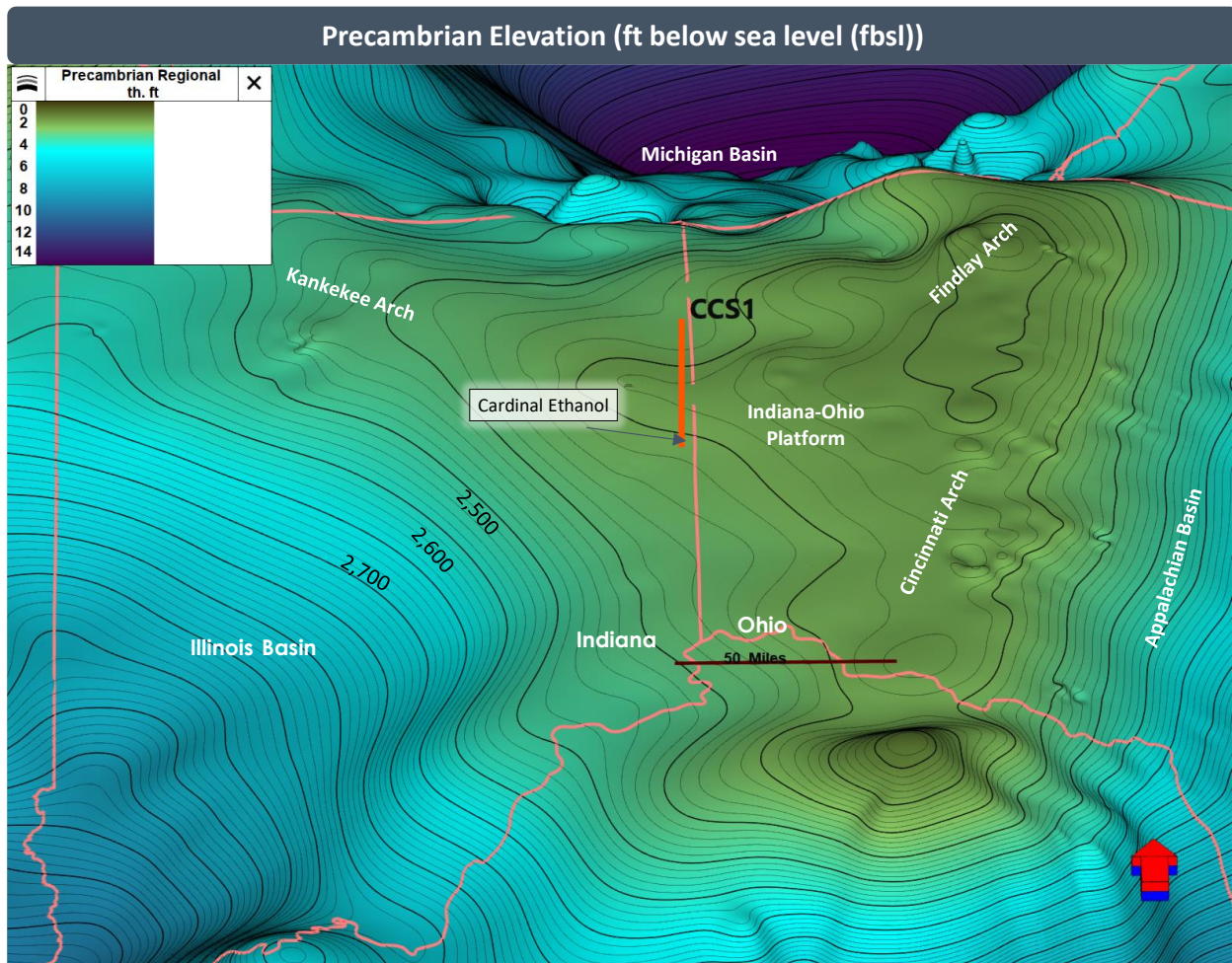


Figure 4. Regional Indiana-Ohio Platform/Arches Province

During the Precambrian (Keweenaw), a period of extension prevailed in North America's mid-continent that led to the formation of the Midcontinent Rift System (MRS) and associated East Continent Rift Basin (ECRB), with the peak of rifting, associated volcanic activity, and deposition of sedimentary rocks occurring at this time (Baranoski, 2002; Drahovzal, et al, 1992).

By the end of the Precambrian Era, Indiana/Ohio was the site of continental-continental convergent plate margin activity. This activity precipitated the Grenville Orogeny. The western

structural boundary of these Precambrian mountains is known as the Grenville Front. Precambrian rocks to the west of this boundary consist of unmetamorphosed felsic igneous and metasedimentary rocks of the Granite-Rhyolite Province. Precambrian rocks of the Grenville Province (GP) lie to the east of this boundary and consist of metamorphic rock. The thrusting and metamorphism related to the Grenville Orogeny occurred approximately 1.06 to 1.03 billion years ago (Dickas et al., 1992). In Late Precambrian time, uplift and erosion occurred.

The Eastern Granite-Rhyolite Province (EGRP) is a Mesoproterozoic province of the North American Midcontinent basement region. The EGRP overlaps and overprints the older Central Plains Orogenic Province (CPO) to the west and is physically bound by the younger GP to the east. The EGRP is separated from the Southern/Western Granite-Rhyolite Province (SGRP/WGRP) to the south by a transitional change in the age of granitic magmatism of the two provinces (Green, 2015).

Erosion of the land mass continued in early Cambrian time, and the seas began a slow transgression from the east. Large quantities of clastics and some carbonates were deposited in the Paleozoic Appalachian Basin. As the sea continued to encroach upon the land, dolomite and limestone were being deposited in deeper waters while deposition of clastics was limited to near shore areas being fed by major drainage systems (Freeman, 1953). There was an uplifting of the Canadian shield near the end of Cambrian time that tilted the sediments of the area. Therefore, the Cambrian section represents an overall transgressive depositional sequence (Harris and Baranoski, 1996).

Much of the land mass was covered by the sea as the Cambrian Period ended and the Ordovician Period began. During the Ordovician Period, marine regression occurred exposing newly deposited sediments to erosion for the first time and resulted in the Middle Ordovician Knox unconformity. Another period of transgression began that resulted in a repeat of Cambrian history with one notable exception: Erosion of fresh sediments covering the land mass was occurring rather than erosion of igneous and metamorphic rocks of the Precambrian crust. Consequently, the lithology of these new deposits reflected the lithologies of the nearest source areas (Freeman, 1953). A series of transgressing and regressing shallow seas, associated with periods of broad, gentle uplifting of the uplands and continued subsidence in the basins dominated the remainder of Ordovician time.

By early to mid-Silurian time, eastern Indiana/western Ohio was close to wave-base while the basins to the west, north, and east received a large amount of sediments (Janssens, 1967). During early Devonian Period, the seas retreated, and uplift occurred, followed by extensive erosion. The seas returned and deposited Devonian-Mississippian shales across the region.

Subsidence and uplift continued well into the Pennsylvanian Period. Movement became slower and more episodic from Late Pennsylvanian until the close of the Paleozoic Era. Erosion or nondeposition prevailed throughout the Mesozoic Era and into the Cenozoic Era. During the Pleistocene Epoch, the region was exposed to Illinoian and Wisconsin glaciation. Post-glacial streams have deposited up to 400 ft of valley fill along stretches of the major river systems.

### **2.1.1 Regional Stratigraphy**

A stratigraphic chart (Figure 5) for southeastern Indiana, southwestern Ohio, and central Kentucky shows the pre-Knox unconformity correlations for the tri-state area (Drahovzal, et al, 1992). The stratigraphic nomenclature used in this report is shown on the generalized

stratigraphic column (Figure 6). A regional cross-section is included to show regional continuity and characteristics of the Paleozoic formations [40 CFR 146.82(a)(3)(i)] (Figure 7). This cross-section includes two Ohio Class I wells critical in establishing the Mt. Simon Sandstone as a suitable injection horizon in eastern Indiana and western Ohio. The datum for this cross section is the Mt. Simon Sandstone and thickening and thinning of the individual geologic units can be seen up through the Trenton Limestone.

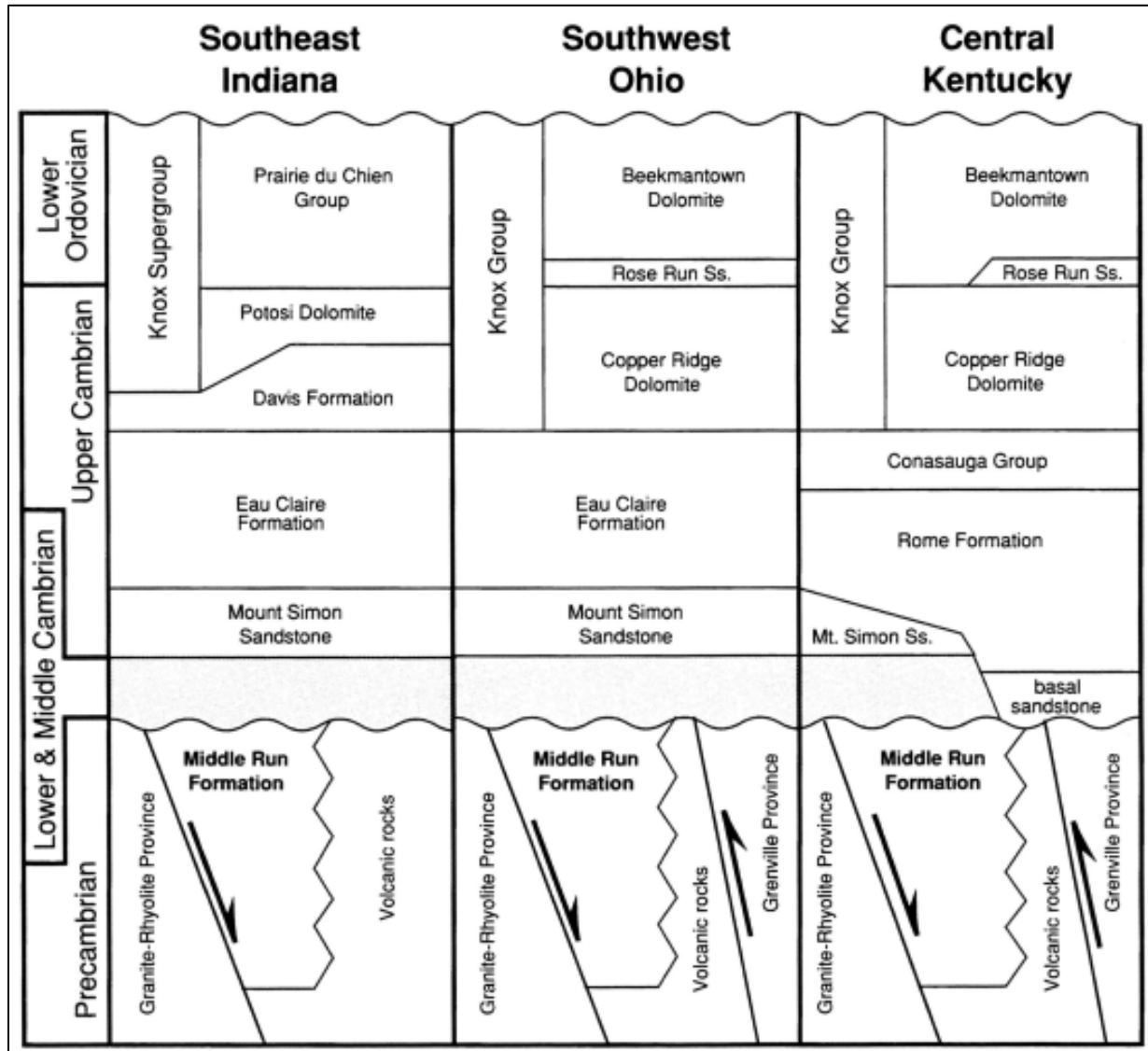


Figure 5: Pre-Knox unconformity stratigraphic correlation chart for southeastern Indiana, southwestern Ohio, and central Kentucky. Post -Precambrian unconformity between the Mt. Simon Sandstone and the Middle Run Formation is indicated (Drahovzal, et al, 1992).

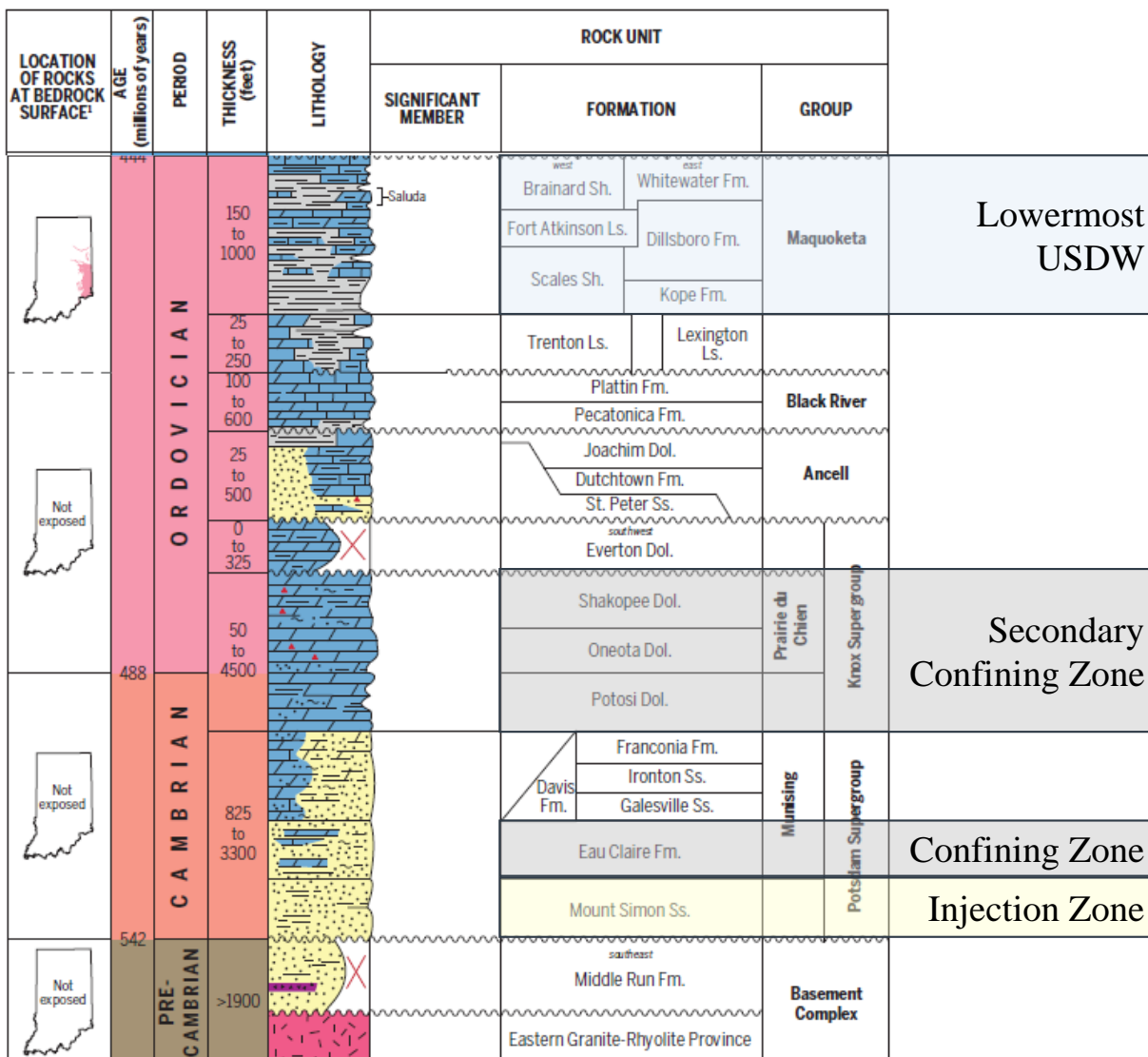


Figure 6: Generalized stratigraphic column of Indiana bedrock including injection, primary confining, secondary confining, and lowest USDW horizons modified from (Indiana Geological Survey, 2016)

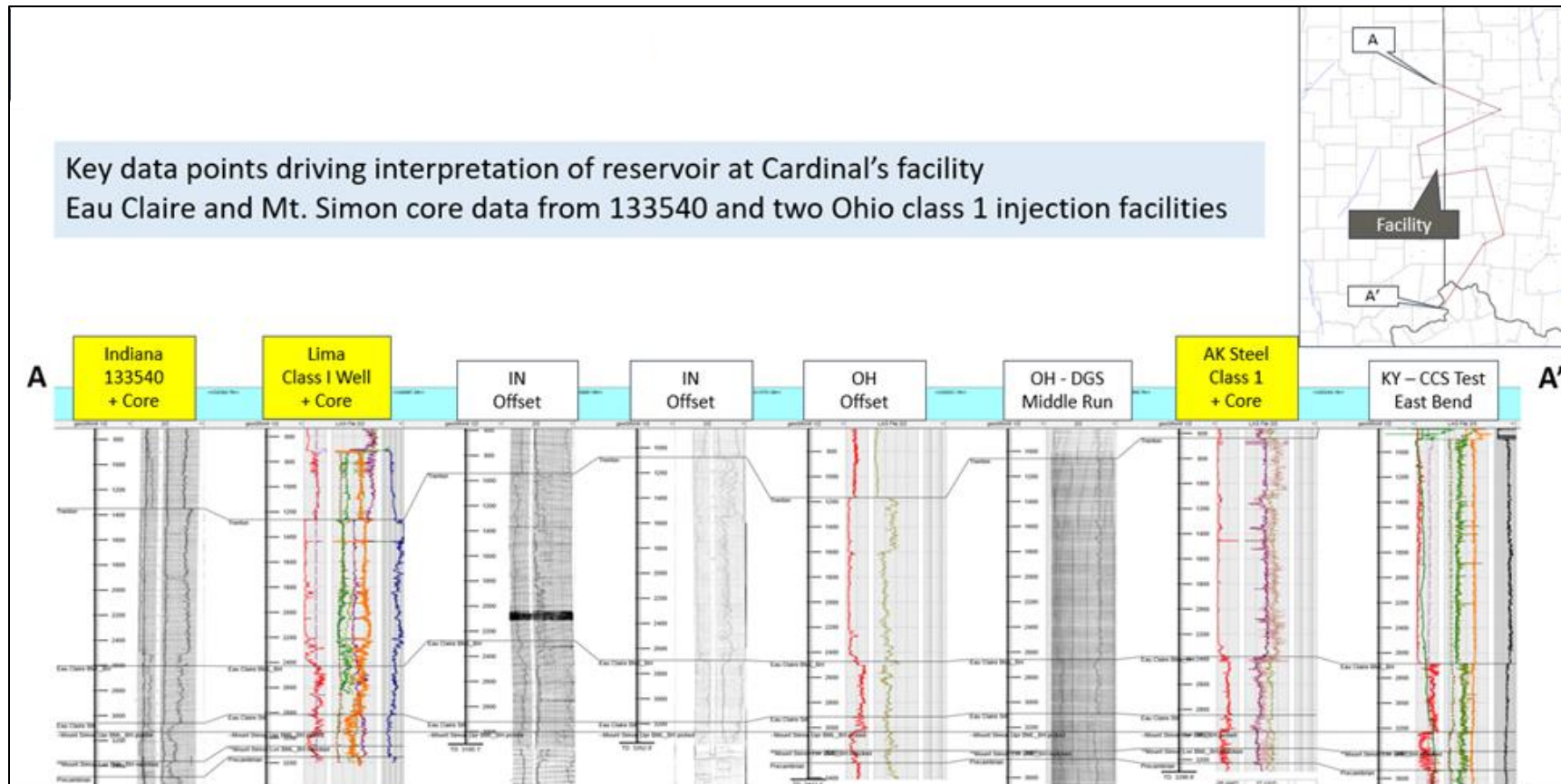


Figure 7: Regional North-South cross section demonstrating regional continuity of formations

#### 2.1.1.1 Precambrian Basement Complex

The Precambrian basement of the Granite-Rhyolite Province/ EGRP consists of high grade metamorphic and igneous rocks (Figure 8). The Granite-Rhyolite Province has been mapped from western Ohio and Kentucky westward to Missouri, Kansas, and Oklahoma (Denison and others, 1984). The Grenville Front, which runs north-south through west-central Ohio ~100 miles east of the project, is the structural boundary that separates the Granite-Rhyolite Province from the GP.

Typical lithologies include granites, rhyolite, trachylite, and quartzite and fine- grained, micrographic to granophyric granite of extensional tectonic origin (Bickford and others, 1986). The GP consists of highly folded, intruded, medium to high grade metamorphic rock that include schist, amphibolite, and gneiss.

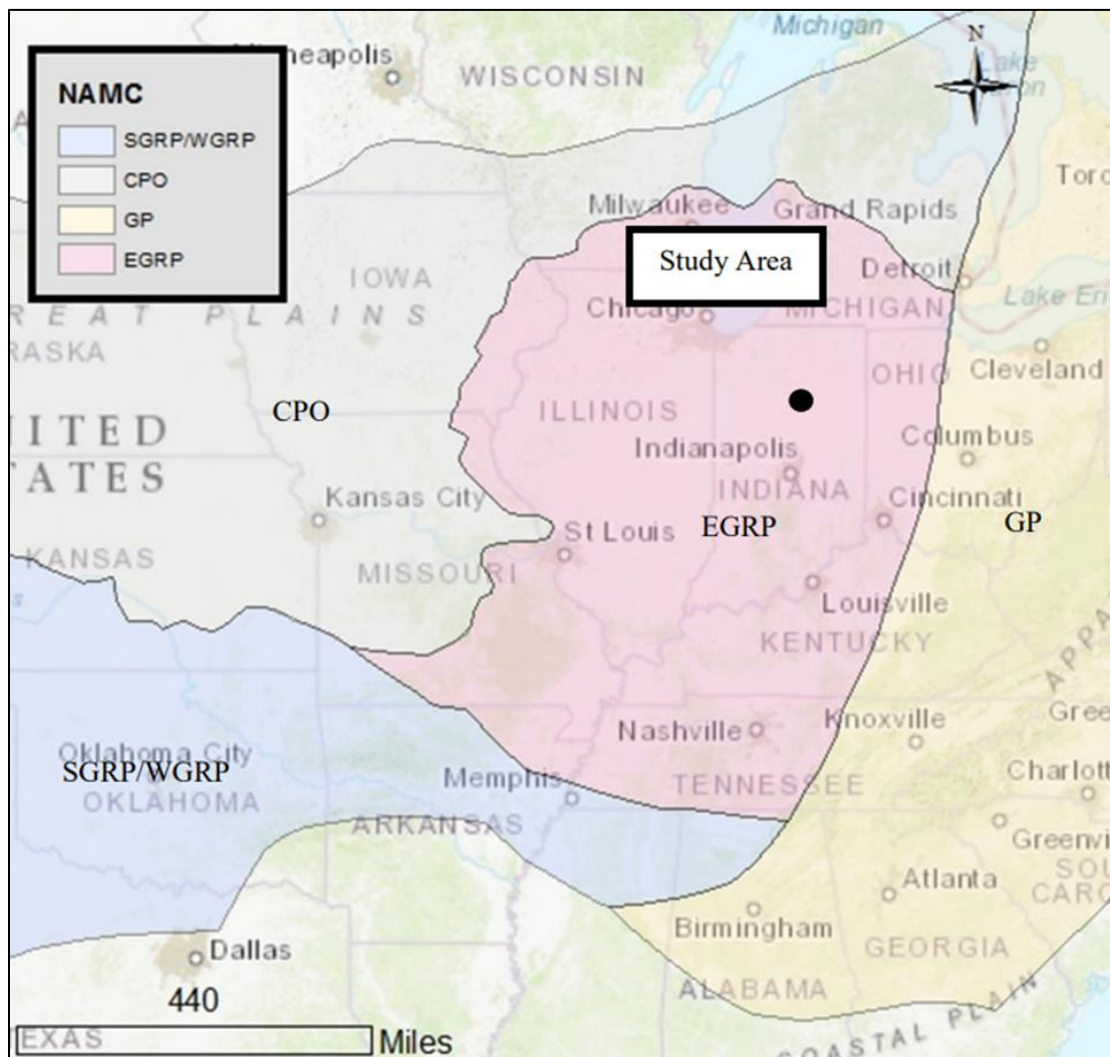


Figure 8: Generalized map of the Eastern Granite-Rhyolite Province and surrounding basement provinces. (Modified by Michael Ray Green, 2015 from Bickford et al., 2015).

#### 2.1.1.2 *Middle Run (Precambrian)*

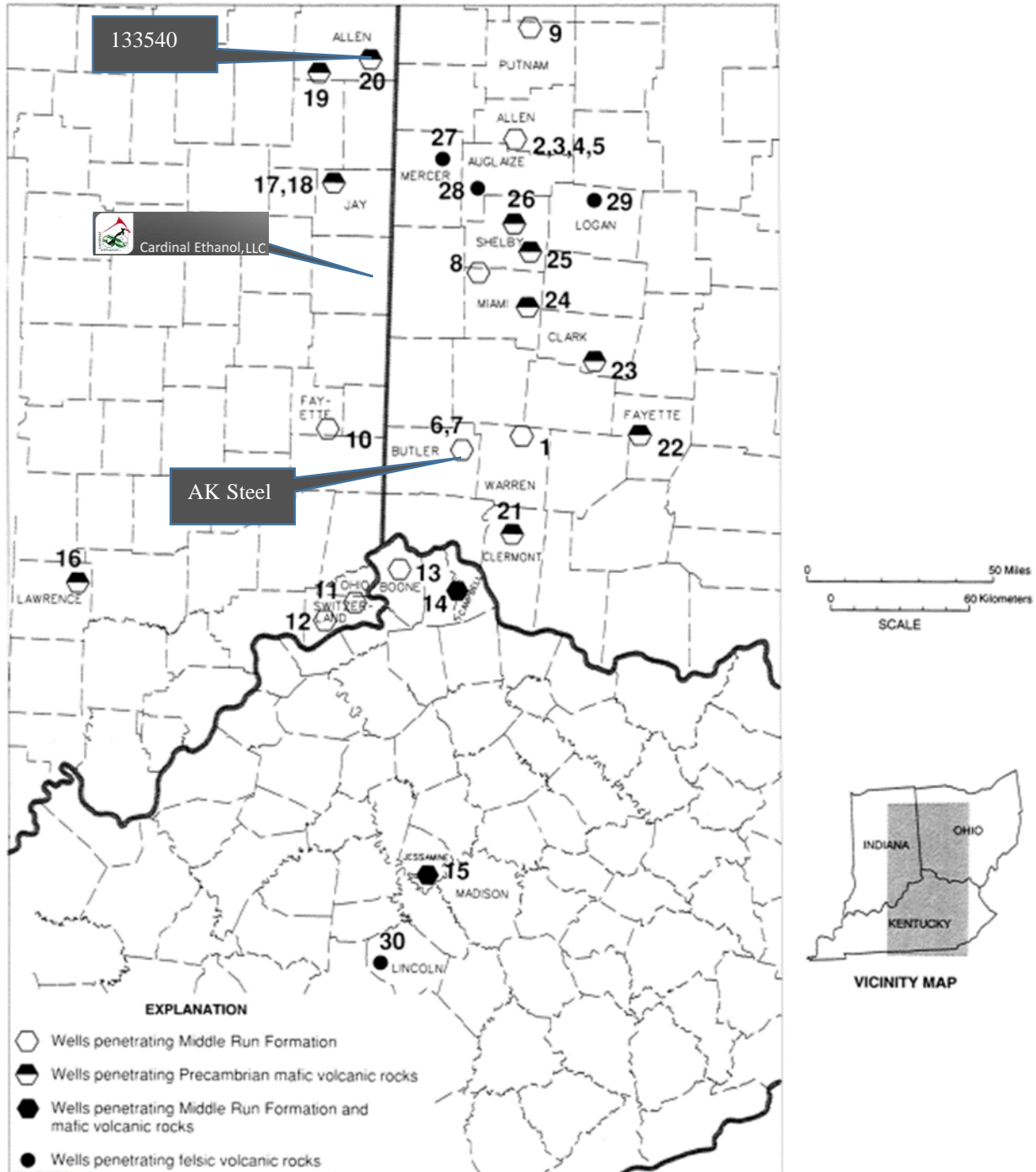
The Middle Run Formation was first recognized as a new formation in the Ohio Department of Natural Resources (ODNR), Division of Geological Survey (DGS) DGS #2627 core located in Warren County approximately 58 miles southeast of the project. Based on core and thin section data, the Middle Run Formation is a tightly compacted, fine to medium-grained, subrounded to subangular, reddish lithic arenite (sandstone) with coarse, angular, weathered feldspar with red clay, quartz, and accessory biotite, magnetite and hornblende lithic clasts composed of (in the order of increasing abundance) volcanic, metamorphic, plutonic, and sedimentary fragments. The formation is well compacted and low porosity. An 80-foot siltstone was also identified in the upper most Middle Run (Dickas et al., 1992). The contact between the Middle Run Formation and the overlying Mt. Simon Sandstone was sharp where penetrated and cored in DGS 2627.

Both the sandstone and the siltstone elements of the Middle Run Formation at DGS #2627 were reported to have no identifiable porosity (Shrake et al., 1990). A thin section analysis of the Middle Run Formation indicated an intergranular porosity of about 0.5% (Shrake et al., 1991). The petrology of the Middle Run Formation has been described as "porosity is almost totally absent where cuttings have been observed in cores, and hence there is small likelihood that the Middle Run Formation could ever be a petroleum reservoir or a site for liquid waste disposal." (Wolfe et al., 1993).

The Middle Run Formation was deposited in a rift-associated sedimentary basin during Late Precambrian time (e.g., Shrake et al., 1991; Shrake, 1991; Drahovzal et al., 1992; Dickas et al., 1992; Lucius and von Frese, 1988). Lithologic similarities with other red clastic sequences associated with the Precambrian Midcontinent Rift System in Michigan and Wisconsin support the interpretation that the Middle Run Formation is related to a rift basin. In addition to lithologic similarities, seismic, magnetic, and gravity data suggest a genetic relationship between the Midcontinent Rift System and the rift basin containing the Middle Run. This relationship further supports the Late Precambrian age assigned to the Middle Run Formation. The Middle Run Formation was deposited in association with and following deposition of East Continent Rift System fill sequences and possibly with later foreland basin development (Baranoski et al., 2009). Geochronological analysis of detrital zircon from the Middle Run Formation supports the deposition of sediments at the end of the Grenville Orogeny (Baranoski et al., 2009). Recent work supports a complex history associated with pre-Mt. Simon Sandstone sedimentation that includes multiple sequences of sedimentary units culminating in the deposition of Middle Run-Foreland Basin sediment deposition followed by erosion prior to deposition of the Mt. Simon Sandstone.

The Middle Run Formation has been identified in seismic reflection surveys conducted in several locations in western Ohio. These surveys indicate the presence of a thick sequence of pre-Mt. Simon Sandstone stratified units consisting of clastic sedimentary layers and possibly layered volcanics (e.g., Richard and Wolfe, 1995; Shrake et al., 1990; Baranoski et al., 2009; Wolf et al., 1993; Dean et al., 2002a and 2002b). The topmost unit of this sequence in western Ohio is the Middle Run Formation (Figure 6).

Figure 9 and Table 4 summarize the wells within the basin that penetrate the Middle Run Formation.



**Figure 9: Map of the study area showing the location and lithology of the Middle Run formation and related intrabasinal volcanic rocks in the ECRB. Lithologic identifications are based on core or cutting samples from wells indicated.**

**Table 4: List of wells penetrating Middle Run Formation and associated mafic and felsic volcanics within the ECRB.**

Map Number	Well Name	County, State	Precambrian Top (Subsea)	Precambrian Thickness Penetrated	Rock Type
1	ODNR DGS No. 2627	Warren Co., Ohio	-2,433'	1,922'	lithic arenite
2	SOHIO No. 1 Vistron	Allen Co., Ohio	-2,261'	1'	lithic arenite
3	SOHIO No. 2 Vistron	Allen Co., Ohio	-2,290'	27'	lithic arenite
4	SOHIO No. 3 Vistron	Allen Co., Ohio	-2,282'	32'	lithic arenite
5	BP Chemicals No. 4 Fee	Allen Co., Ohio	-2,279'	147'	lithic arenite
6	Armco Steel No. 1 Fee	Butler Co., Ohio	-2,570'	61'	lithic arenite
7	Armco Steel No. 2 Fee	Butler Co., Ohio	-2,557'	57'	lithic arenite
8	Sun Oil No. 1 Levering	Miami Co., Ohio	-2,288'	130'	lithic arenite
9	Ohio Oil No. 1 Barlage	Putnam Co., Ohio	-2,628'	9'	lithic arenite
10	Gulf Oil No. 1 Scott	Fayette Co., Ind.	-2,971'	25'	lithic arenite
11	Ashland Oil No. 1 Collins	Switzerland Co., Ind.	-3,062'	58'	lithic arenite
12	Ashland Oil No. 1 Eichler	Switzerland Co., Ind.	-3,246'	111'	lithic arenite
13	Ford No. 1 Conner	Boone Co., Ky.	-2,807'	371'	lithic arenite
14	Ashland Oil No. 1 Wilson	Campbell Co., Ky.	-2,745'	58'	lithic arenite, basalt
15	Texaco No. 1 Sherrer	Jessamine Co., Ky.	-2,326'	2,008'	lithic arenite, basalt
16	Farm Bureau No. 1 Brown	Lawrence Co., Ind.	-5,850'	156'	basalt
17	Farm Bureau No. 1 Binegar	Jay Co., Ind.	-2,384'	62'	basalt
18	Pet. Dev. No. 1 Binegar	Jay Co., Ind.	-2,403'	44'	basalt
19	Tecumseh No. 1 Gibson	Allen Co., Ind.	-2,654'	41'	basalt
20	NIPSCO No. 1 Leuenberger	Allen Co., Ind.	-2,687'	188'	basalt
21	Continental No. 1 Wykoff	Clermont Co., Ohio	-2,485'	134'	basalt, andesite
22	Kewanee No. 1 Barnes	Fayette Co., Ohio	-2,288'	78'	basalt, troctolite
23	Friend No. 1 Mattison	Clark Co., Ohio	-2,279'	1,281'	basalt, rhyolite
24	NAP No. 1 Walker	Miami Co., Ohio	-2,218'	257'	basalt, gabbro
25	Sun No. 1 Nelson	Shelby Co., Ohio	-2,134'	91'	basalt, gabbro
26	Gump No. 1 Fogt	Shelby Co., Ohio	-2,261'	62'	basalt
27	Harner No. 1 Yewey	Mercer Co., Ohio	-2,263'	35'	rhyolite*
28	West Ohio No. 1 Hoelscher	Auglaize Co., Ohio	-2,144'	27'	rhyolite
29	Ohio Oil No. 1 Johns	Logan Co., Ohio	-2,062'	109'	rhyolite
30	California No. 1 Spears	Lincoln Co., Ky.	-4,609'	357'	rhyolite

\* Data from Lucius and Von Frese, 1988.

### 2.1.1.3 Mt. Simon Sandstone/Injection Zone (Cambrian)

At the Hoosier #1 site, the Cambrian-Ordovician Sauk sequence unconformably overlies the Middle Run Formation (Figure 6). This includes the Mt. Simon Sandstone, the Eau Claire, and the Knox formations.

The basal sandstone unit, named the Mt. Simon Sandstone, is a quartz-rich, occasionally arkosic, fine to coarse-grained sandstone deposited unconformably upon the Precambrian (Janssens, 1973). It is interpreted to be a barrier bar sequence which migrated across a basal lagoonal estuarine sequence (Saeed, 2002). The Mt. Simon Sandstone is a thick sandstone present in several states including Indiana, Illinois, Michigan, western/northern Kentucky, and western Ohio (Baranoski, 2007). The Mt. Simon Sandstone is a clear, very bright red to yellowish orange, or white, fine to coarse grained, poorly sorted, friable, hematitic, feldspathic quartzose sandstone (generally equal portions of quartz and feldspar). Isolated sandstone beds within the formation can be well-sorted and extremely permeable. Over the past decade, the Mt. Simon

Sandstone has been the target of numerous studies to evaluate its potential for CO<sub>2</sub> sequestration over a wide range of target areas (e.g., Medina et al., 2010, Wickstrom et al., 2005, Barnes, et al., 2009, MRCSP 2005, 2011). These studies verify the presence of the Mt. Simon Sandstone throughout eastern Indiana and western Ohio at much shallower depths than in other locations in the Michigan and Illinois basins.

The Mt. Simon Sandstone was deposited in an area limited to western Ohio and the adjacent proto-Michigan-Illinois Basin. The eastern limit of the Mt. Simon Sandstone is redefined along a north–northwest-trending, broad, Precambrian paleotopographic arch (exposed Laurentian craton), which extends in the subsurface from an area north of present-day western Lake Erie, southward to the Ohio River, and corresponds to the northwestern Rome Trough boundary fault system. The Mt. Simon Sandstone subcrops along the northern portion of this north–northwest-trending arch. Along the southern portion of this trend, the Mt. Simon Sandstone thickness thins to the east, grading laterally with mixed clastic-carbonate Conasauga Group facies (Baranoski, 2007).

Regionally, it has been noted that the lower Mt. Simon Sandstone is conglomeritic and arkosic (Kemron/AK Steel). It grades upwards into a sandstone or sandy dolomite. Thin green and red shale streaks parallel very porous and permeable red sands just above the base. The middle/upper Mt. Simon Sandstone contains medium to coarse-grained, poorly sorted, round to angular, frosted, poorly consolidated sandstone. Minor amounts of silica or carbonate cement with possible feldspar growth have been reported. Dolomite and hematite may act as additional cement. It becomes increasingly calcareous towards the top and contains a few marine fossils. Some siltstone layers and thin shales are present in the upper zone. Glauconite is only present where the Eau Claire overlies the Mt. Simon Sandstone in western Ohio (Janssens, 1973).

#### *2.1.1.4 Eau Claire/Primary Confining Zone (Cambrian)*

The Eau Claire Formation (Figure 6) overlies the Mt. Simon Sandstone at the Hoosier #1 site. This formation consists of interbedded glauconitic sandstones, siltstones, shales, and dolomite. Siltstones and sandstones are light to medium greenish-gray, brown, or very light orange. Interbedded green and reddish-brown glauconitic shales are more prevalent near the top of the formation. Limestone may occur in trace amounts (Janssens, 1973). The contact of the Eau Claire Formation with the Mt. Simon Sandstone is transitional with the base of the Eau Claire Formation being a glauconitic siltstone and very fine-grained sandstone. Increasing carbonates towards the top of the section indicates increasingly marine conditions during deposition of the Eau Claire Formation. The Eau Claire Formation undergoes facies change to the east where it becomes the Rome Formation and the Conasauga Shale. This facies change runs north-south near the top of the Findlay and Cincinnati Arch Axes, which is east of the Hoosier #1 site and significantly outside the Area of Review (AoR). Thickness of the Eau Claire Formation ranges from 400 ft to over 700 ft in eastern Indiana.

#### 2.1.1.5 *Davis (Cambrian)*

The Eau Claire Formation is overlain by the Davis Formation which is conformable with both the Eau Claire Formation and overlying Knox Dolomite (Figure 6). The following rock types have been identified in the Davis Formation:

1. Dolomite that is brownish gray, fine to medium crystalline, glauconitic, slightly silty, sandy, and pseudo-oolitic,
2. Siltstone that is yellowish gray, dolomitic, glauconitic, and slightly feldspathic,
3. Shale that is dark gray, hard, brittle, and calcareous,
4. Limestone that is gray to brownish gray, dense, shaly in many places, somewhat pseudo-oolitic, and interbedded with glauconitic siltstone and fine-grained sandstone (Becker; et al, 1978).

#### 2.1.1.6 *Knox/Potential Secondary Confining Zone (Cambrian-Ordovician)*

The Davis Formation is overlain by the Cambrian-Ordovician Knox Dolomite (Figure 6). When sea floor spreading slowed during tectonically quiescent periods, carbonate deposits of the Knox Group occurred on the shelf (Hansen, 1997 and Milici, 1996). In southeastern and eastern Indiana, this depositional time is referred to as the Knox Supergroup (Prairie Du Chien Group and Potosi Dolomite). The transition from deposition on a passive margin to deposition on a convergent margin caused the Knox Dolomite to be truncated by a major regional unconformity (Drahovzal, et al, 1992, Read 1980). The continent was uplifted, and karst topography and associated drainage patterns probably formed on the exposed surface (Dolly and Bush, 1972; Mussman and Read, 1986: from Drahovzal, et al, 1992). This formation consists of dolomite, shale, sandstone, and stratigraphically restricted limestone. Stromatolitic structures and fossils have been recognized in cores from the Knox (Botoman, 1975).

The lower and middle Knox formations are Cambrian in age. The Knox Formation is micro crystalline to coarse crystalline dolomite with interbedded pyritic shale and clear sandstone at its base. The middle Knox Formation is micro crystalline to medium crystalline, partly sandy dolomite and silty dolomite with sand and occasional chert, shale, silicified oolite and pebbles. The upper Knox Formation is Ordovician in age. This part of the formation is porous to occasionally dense, fine crystalline dolomite. It may occasionally have associated shale, glauconite and chert. The Knox Dolomite has an approximate thickness of 335 ft at the Hoosier #1 site. Variation in thickness across Indiana and Ohio can be attributed either to depositional thinning, erosion before the Middle Ordovician, or a regional truncation of individual units.

#### 2.1.1.7 *Ancell – Indiana/Wells Creek – Ohio (Ordovician)*

After the Knox Formation surface erosion, subsidence created a shallow sea that covered the area, resulting in a brief period of intercalated clastic and carbonate sediments, represented by the Ansell/Wells Creek Formation (Figure 6) (Drahovzal, et al, 1992). A sharp contact is easily seen on gamma ray - neutron logs and in samples, between the clean Knox Dolomite and the clastic, sandy dolomite of the Wells Creek Formation. The Wells Creek Formation consists of sandstone, siltstone, gray, green, and brown shale, and argillaceous and sandy dolomite. Sandstone interbedded with dolomite is generally fine-grained but may be fine to coarse-grained. Internally this unit is called the Glenwood Formation, which is overlain by the Gull River Formation, both nomenclatures are commonly used in Ohio.

#### 2.1.1.8 *Black River (Ordovician) Group*

Subsequent encroachment from the east to west caused deposition of the Ordovician Black River Group (Figure 6) (micritic to finely crystalline limestone) in environments ranging from subtidal to intertidal (Drahovzal, et al, 1992). This formation consists of lithographic limestone with sandstone, chert, and brown shales. Thin interbedded limestone is present in the upper section of the Black River Group, while the lower section contains lenses of fine-grained brown dolomite. The Black River Limestone terminates with a volcanic metabentonite zone (Botoman, 1975). After Black River Group deposition, the epeiric sea deepened and became more normal marine in composition. Bentonites at the top of the Black River Group are evidence that the Taconic Orogeny was increasing in intensity to the east (Drahovzal, et al, 1992). Deepening of the sea resulted in the deposition of the basal, subtidal, and open-shelf facies of the Ordovician Trenton Limestone. As a result of the subsidence of the proto-Appalachian Basin and the early stages of the Taconic Orogeny, the deposition of the basal Trenton facies ended which is marked by a change in depositional strike. This caused shallowing of the sea to the northwest and the deposition of the thick carbonates of the platform facies of the Trenton Limestone.

#### 2.1.1.9 *Trenton Limestone (Ordovician)*

Overlying the Black River Group is the Ordovician Trenton Limestone (Figure 6). The Trenton Limestone consists of limestone that becomes increasingly dolomitic in northern Indiana, and in places it is completely dolomitized. The Trenton Limestone is tan to light tannish gray to medium tannish gray. The color variation in the limestone is due to the variation in the content of skeletal grains versus micrite where the darker color correlates with the higher micrite content. In the dolomite the size of the crystals appears to be the controlling factor the more coarsely crystalline phases are lighter colored. The Trenton Limestone is everywhere in the subsurface of Indiana except for far southeastern Indiana as noted below. The Trenton Limestone has a maximum thickness of 265 ft in Steuben County in northeastern Indiana, and it thins to zero thickness in far southeastern Indiana through what is believed (although not well understood) to be a geographically progressive facies change with the Kope Formation, which is replaced farther southeastward by the Lexington Limestone through a similar facies change (Gray, 1972b; Droste and Shaver, 1983; and Keith, 1985). This narrow area of dual facies change extends northeastward from Spencer and Perry Counties to eastern Fayette County (Keith, 1985).

#### 2.1.1.10 *Cincinnatian/Maquoketa Group (Ordovician)*

The Trenton Limestone is overlain by the Upper Ordovician Cincinnatian Series (Figure 6), a succession of fossiliferous limestone and gray calcareous shale or siltstones. For the purposes of this project the Cincinnatian Series is subdivided into the Kope (dark brown to nearly black shale and minor interbedded limestone), and Maquoketa formations. The shale dominated Maquoketa Shale approaches 1,000 ft in eastern Indiana but is only around 200 ft in western Indiana. Most of the shale is gray and calcareous, but brown carbonaceous shale 100 ft to 300 ft thick characterizes the lowermost part of the group. Limestone, which constitutes about 20 percent of the group, is most abundant in the upper part. The Maquoketa is a clastic wedge that spread across Indiana from east to west and is the first of the Paleozoic sediments to have had an evident eastern source. The Maquoketa Shale has been identified as the lowest USDW in the project area (Figure 6).

### **2.1.2 Regional Structure**

This section discusses the regional Precambrian structural element and the relation to the overlying sediments where the Mt. Simon Sandstone is the injection zone, and the Eau Claire Formation and lower portion of the Knox Formation act as confining units.

Major features of Indiana consist of parts of the Cincinnati and Kankakee Arches and segments of the Illinois and Michigan basins (Figure 4). The structural axis of the Cincinnati and Kankakee Arches extends from southeastern to northwestern Indiana. The crestal area of the arch is broad and flat and is as much as 75 miles wide. The Illinois Basin is the large structural depression southwest of the arch, and the Appalachian Basin is the structural depression to the east of the arch. Regional dip from the crestal area into the basins is between 25 ft and 35 ft per mile. Detailed mapping of the Trenton Limestone indicates that the lower Paleozoic sequence is disturbed by minor faulting (Dawson, 1971). Although there is a lack of deep well control along the trace of the faults, it is presumed that the Precambrian basement was also disturbed with displacement. Generally, less than 100 ft of displacement is observed on the Trenton Limestone (Becker, et al, 1978).

Sparse well data, magnetic gradient models, and scattered surface seismic data has been used to map the crystalline basement. In Figure 10, crystalline basement is defined as pre-rift igneous rock. Shaded areas indicate the Grenville (metamorphic) and Granite-Rhyolite (igneous) Provinces adjacent to the ECRB, which were mapped using basement well control. The fault boundaries of the ECRB are shown by bold lines. Areas within the ECRB were mapped using a combination of magnetic anomaly trends and seismic data. Circles within the basin indicate the location of estimated depths to magnetic basement derived from magnetic anomaly data. Volcanic rocks interpreted to be part of the rift-fill sequence are not considered part of the crystalline basement. No wells have penetrated the pre-rift crystalline basement beneath the basin fill sequence; therefore, the mapping of this surface is highly speculative (Drahovzal, et al, 1992).

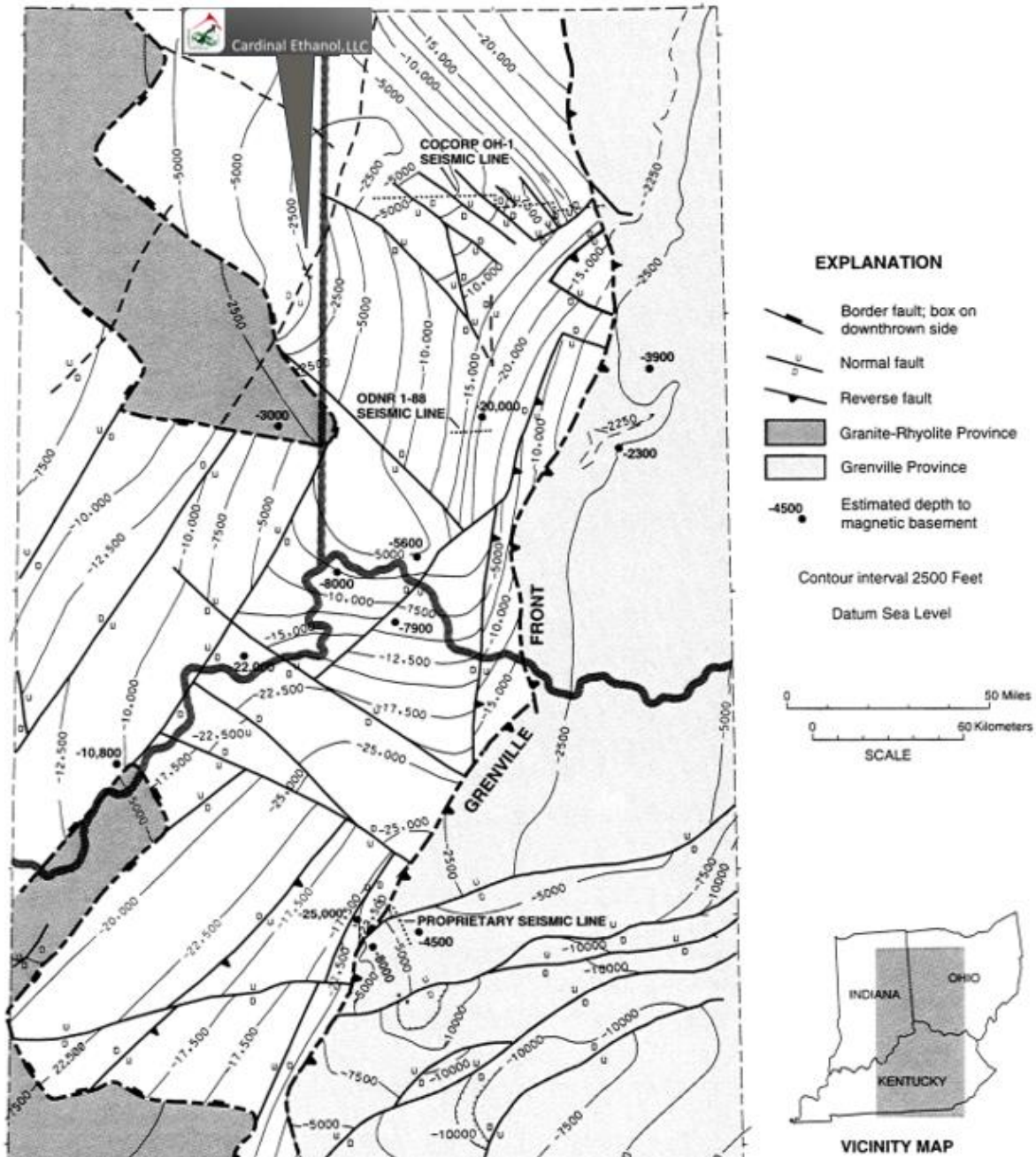


Figure 10: Structure contour map of the Precambrian crystalline basement surface. (Drahovzal, et al, 1992).

West of the Grenville frontal thrust, the top of the crystalline basement changes lithologically, and abruptly deepens to depths as great as 27,500 fbsl. The overall structure varies from a deep basin immediately adjacent to the Grenville Front (7,500 ft to more than 25,000 ft) to a much shallower surface to the west (2,500 ft to 12,500 ft). A broad, south-east plunging arch extends from an upthrown block of Granite-Rhyolite Province rock in eastern Indiana into southwestern Ohio, dividing the basin into deeper portions both to the north and south. The Fort Wayne Rift trend (Figure 11), located approximately ten miles north, defines another northwest-oriented high area in eastern Indiana and western Ohio that also separates deeper portions of the basin

(Drahovzal, et al, 1992). Located approximately six miles northeast of the project, the questionable Auglaize fault/structural trend ends in Ohio and is not mapped into Indiana.



Figure 11: Ohio fault lines map showing Fort Wayne rift and Auglaize Fault (ODNR Division of Geological Survey, 2022)

While the Auglaize Fault is considered questionable by ODNR, its potential proximity to the project site warranted further investigation. Historically, much of the seismicity in Ohio has been centered near the town of Anna in Shelby County. In the 1970s, the Nuclear Regulatory Commission contracted with researchers affiliated with the University of Michigan to investigate

the possible causes of the seismicity. Several engineering firms, including Stone & Webster and Dames & Moore, were also commissioned to investigate the area.

It is from these studies that the Auglaize fault was first mapped (Figure 12). The mapped Auglaize Fault terminates to the southwest at the Anna-Champagne fault and does not extend to the state line, as it does on later maps. The authors noted that none of the faults mapped were exposed at the surface or had been described in the literature at the time (Jackson, 1982). Of the three potential faults that were identified, the Auglaize Fault had the least evidence for its existence. Its presence was inferred from well log data alone; unfortunately, none of the data used for the interpretation was published with the map (Jackson, 1982).



Figure 12: One of the early published maps detailing potential faults in the area of Anna, Ohio (reference)

In the early 1990s, Wickstrom and others expanded on the idea of the three postulated faults and extended the Auglaize Fault southwest all the way to the Indiana border as can be observed in current ODNr maps (Figure 11) (Wickstrom, 1993). The only data available at the time were

the previous maps from the earlier report and their mapped depositional trends of the lower Paleozoic strata which the authors believed were controlled by faults. While these depositional trends could be caused by existing faults, there could be other possible explanations.

In summary, it appears that the closest documented Precambrian faulting with Paleozoic reactivation is in the Fort Wayne Rift zone. The highly speculative Auglaize Fault (Figure 11) has questionable Precambrian displacement and highly unlikely Paleozoic movement (Baranoski, 2002). The Auglaize Fault is not expected to present a hazard to the project. Further discussions on local structure and interpretation of seismic lines acquired for the project can be found in Section 2.3.

## 2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Table 5 is the site-specific stratigraphic column for the project. As discussed in Section 2.1.2, the closest regional structural features to the project are the Fort Wayne Rift Zone and the questionable Auglaize Fault at ten and six miles to the north and northeast, respectively.

The lowermost USDW is estimated to be at 450 ft in the Maquoketa Shale based on Well Permit Number 30922 (IGS Well ID/PDMS 144860) located 1.5 mi southwest of the proposed CCS1 location (Section 2.8.4). There is approximately 2,709 ft between the top of the injection zone and the lowermost USDW; this interval includes approximately 487 ft of the Eau Claire Shale that is the primary confining zone (Table 5).

**Table 5: Site specific stratigraphic column and formations of use.**

Period	Group	Formation	Use	Brief Description	
	Undifferentiated		Undifferentiated	The deepest USDW is estimated to be at 450 ft.	
	Silurian Bedrock				
Ca Ordovician mbr	Maquoketa	Maquoketa	Lowermost USDW	Unconsolidated glacial deposits	
		Kope	Undifferentiated		Gas production target to be avoided
		Trenton	Gas Production		
	Black River	Black River	Undifferentiated	Unconsolidated	
		Pecatonica			
	Ancell	Joachim			Undifferentiated
		Gull River			
		Glenwood			
	Knox	Knox	Monitoring Interval	The Knox is composed of white to brown, very fine to coarse-grained, crystalline to sugary dolomite, containing pyrite, white and light blue oolitic chert, and dolomite rhombs with fossil fragments. Portions of the Knox are vuggy and thus the unit	
		Shakopee	Potential Secondary Confining		
Oneota					
Potosi					

	Potsdam	Davis	(~988 ft thick)	contains some intervals capable of acting as buffering units.
		Eau Claire	Primary Confining (~487 ft thick)	Interbedded shales, and dolomite. Interbedded green and reddish-brown glauconitic shales are more prevalent near the top of the formation.
		Eau Claire Silt	Potential Secondary Storage Formation (~59 ft thick)	Interbedded glauconitic sandstones, siltstones, shales. Siltstones and sandstones are light to medium greenish-gray, brown, or very light orange.
		Mt Simon	Injection Zone (~501 ft thick)	Lies unconformably upon the Middle Run (Precambrian). This is evident by the abrupt change from the poorly sorted, heterogenous, angular, well cemented rocks of the Middle Run and the lighter, homogenous, less cemented partially friable basal Mt. Simon Sandstone.
Precambrian	Precambrian	Middle Run and Precambrian Basement	Lower Confining	The Middle Run is generally a medium to dark reddish brown, argillaceous, well-sorted, fine grained quartzose feldspathic sand. The Precambrian basement consist of rhyolite, trachyte, and fine grained, micrographic to granophyric granite of extensional tectonic origin.

To develop the best understanding of the site-specific geology for the project a comprehensive database was compiled of publicly available geophysical well logs from Indiana and Ohio. Interpretation of these well logs were used to develop the static model for the region. Within 50 miles, 17 wells penetrate the Mt. Simon Sandstone. These wells were used to assess the geology at the project site.

The closest wells that penetrated the Mt. Simon Sandstone and have well log data are approximately 12 to 15 miles southwest and 20 miles northwest of the project site. The closest well that penetrated the Precambrian basement with log data is approximately 28 miles east of the project site. Minimal data availability from formations below the Trenton does not allow for detailed maps for these formations. Additionally, there were 306 Trenton wells within 25 miles of the project used for modeling of shallower horizons.

Figure 13 displays the well logs from nine offsetting wells that penetrate the Trenton Limestone and deeper formations. Six of the wells are within eight miles of the site which penetrate the Trenton Limestone through to the Potosi Formation (Table 5). Only three geophysical well logs penetrate the Precambrian basement and provide data for the full Mt. Simon Sandstone section within 12 – 28 mi of the project. The cross section shows:

- The Maquoketa Shale to Trenton Limestone formations thicken to the east
- Slight thinning to the east
  - Trenton Limestone to Knox Unconformity
  - Knox Group to Eau Claire Formation
  - Eau Claire Formation to Mt. Simon Sandstone

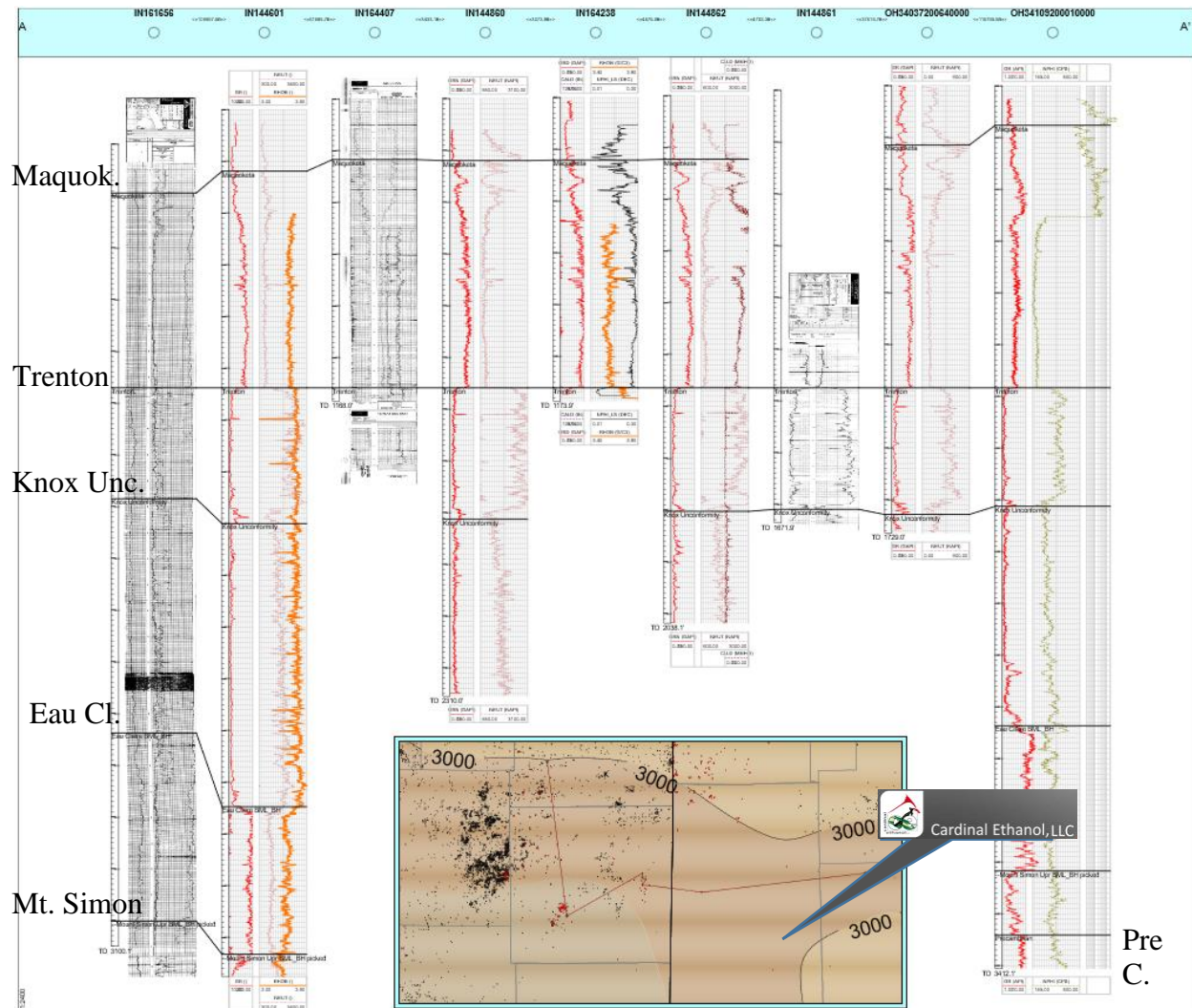


Figure 13: Cross section - thickening of Maquoketa to Trenton to the east and slight thinning to the east.

Structure and thickness maps were generated for the Precambrian, Mt. Simon Sandstone, Eau Claire Formation, and Trenton Limestone using existing publicly available well log data (Figure 14 to Figure 17). The proposed CCS1 well location is shown on each map along with the broad Indiana-Ohio platform and the associated arches. The maps demonstrate the continuous nature of these formations throughout the region, and do not show evidence for regional pinch-outs or structural traps in these formations.

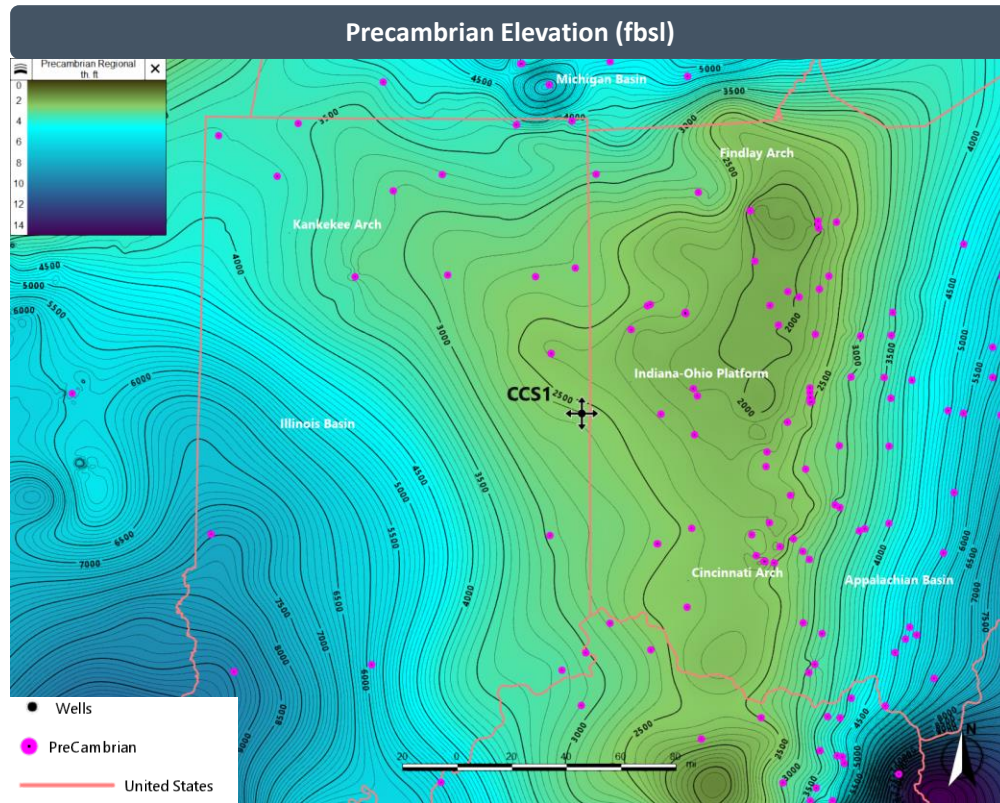


Figure 14: Regional Precambrian lower confining zone elevation

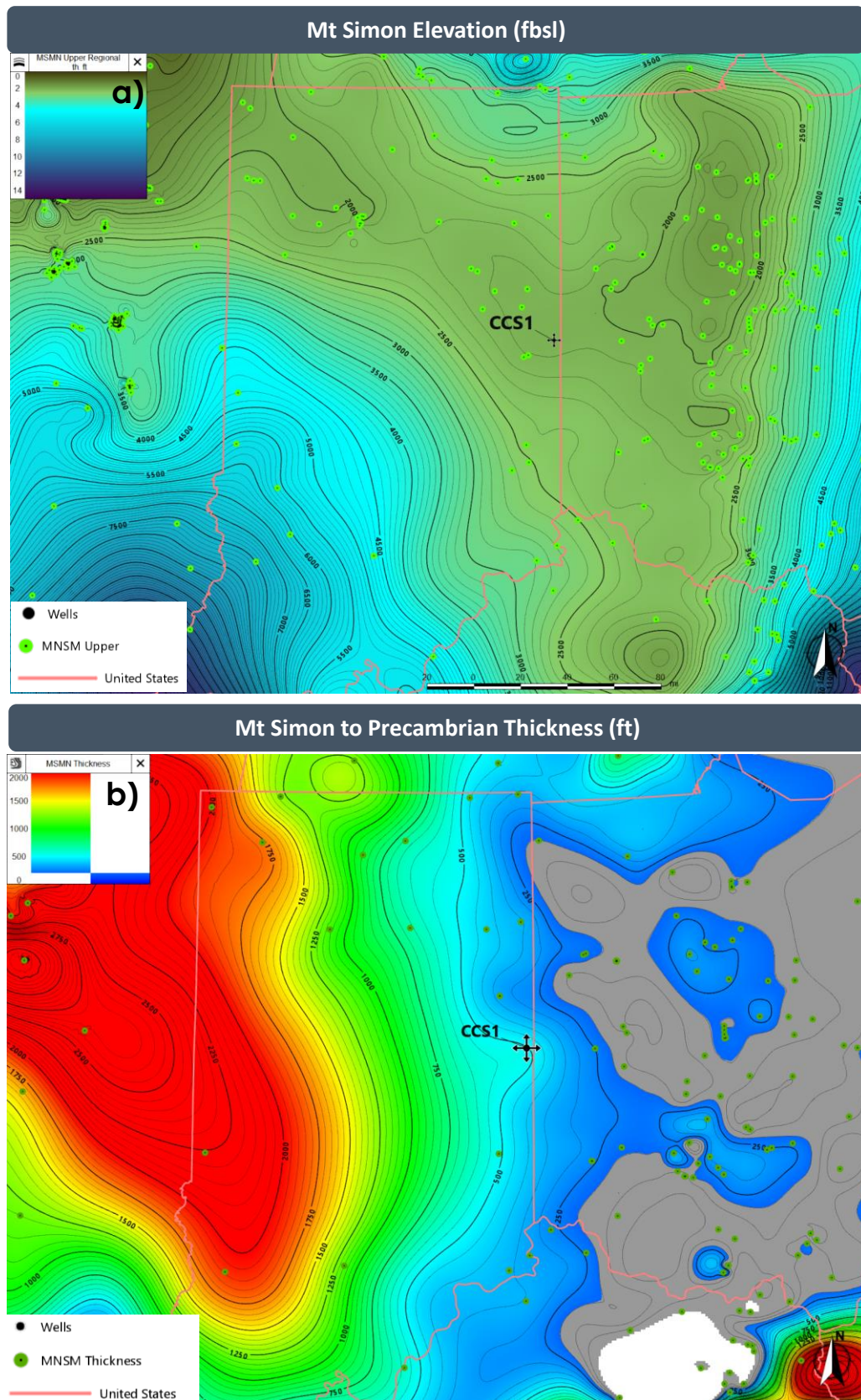
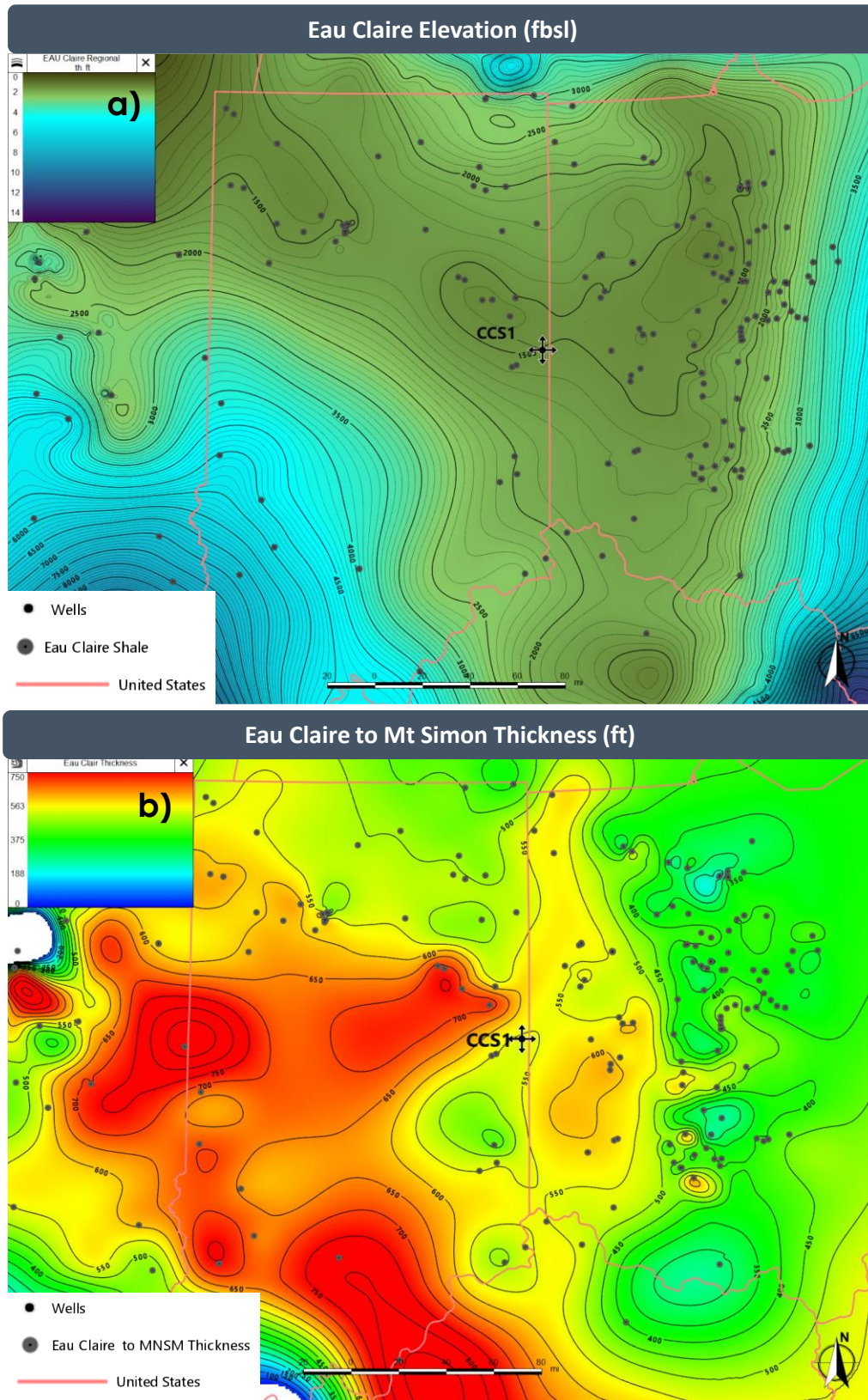


Figure 15: Regional Mt Simon Sandstone injection zone a) elevation and b) thickness



**Figure 16: Regional Eau Claire Formation upper confining zone a) elevation and b) thickness**

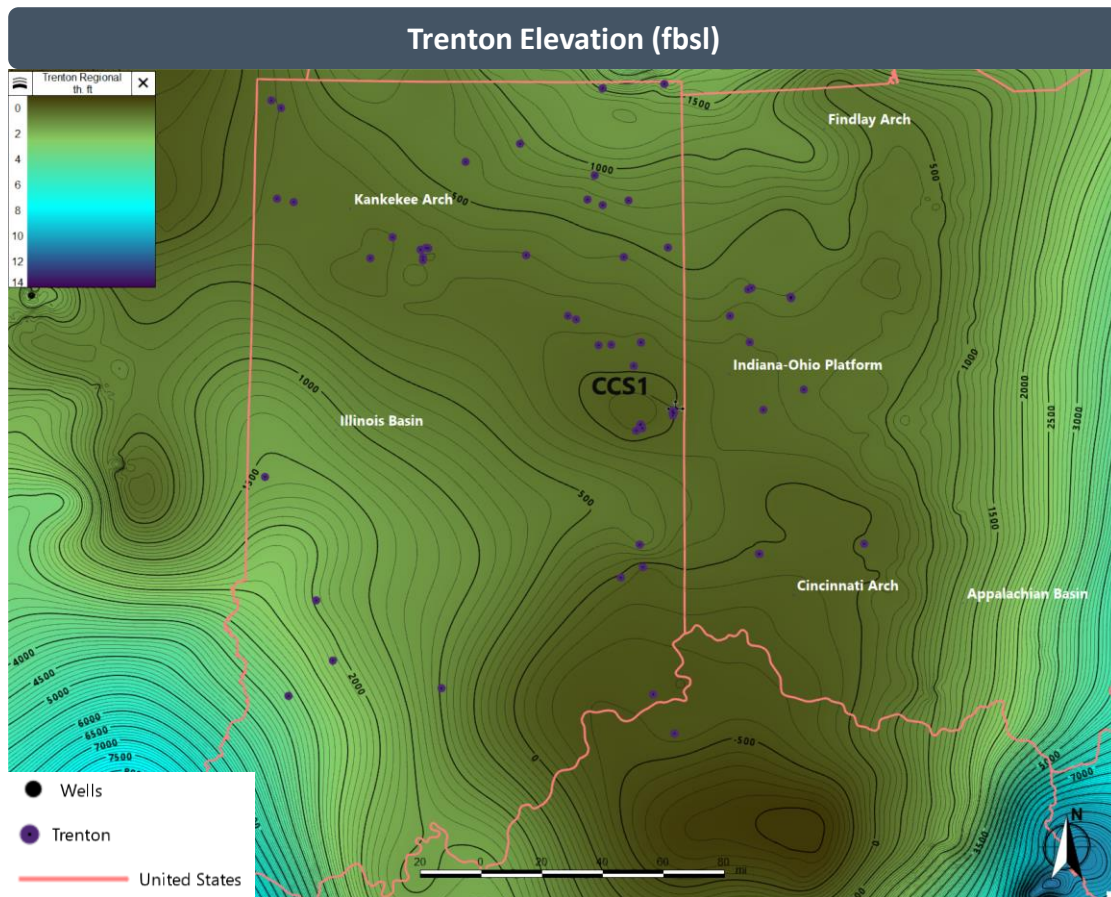


Figure 17: Regional Trenton Limestone elevation

The Knox Dolomite has been identified as a secondary confining zone should injection zone fluids migrate past the Eau Claire Shale (Section 2.2.1.3). Low porosity and permeability values have been measured in part of the Knox Dolomite that corresponded to siltstones, shales, and dense dolomites at the INEOS (BP Lima) Nitriles disposal site (INEOS USA, LLC, 2015)

### 2.3 Faults and Fractures [40 CFR 146.82(A)(3)(ii)]

Based on Class I well research, it is anticipated that fracture occurrence will likely be a localized phenomenon with a few short and open natural fractures (AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021; INEOS (BP Lima) Nitriles, August 22, 2016). The Pre-Operational Testing Program details the geophysical log and core data that will be acquired and evaluated to characterize potential fractures that could impact the long-term integrity of the confining zone (Attachment 5: Pre-Op Testing Program, 2022).

Three 2D seismic lines (Line 1 EW, Line 2 NS, Line 3 Short NS) were acquired and interpreted to provide information on the subsurface structure around at the project (Figure 18).

Approximately 19 miles of seismic data were acquired in early 2021 by Integrity Geophysical Services, Inc. The data were acquired with a vibrator truck using a one (1) millisecond sample rate, a broad band and long duration sweep, with multiple sweeps and diversity stacking. A stack fold of 144 was achieved for the acquisition on the surveys. The seismic lines were reprocessed by Earth Signal (Calgary, Alberta, Canada).

Interpretation of the Precambrian structure have identified features that could be interpreted as minor or fracture planes (Figure 19 to Figure 22). Seventeen potential minor faults were identified; however, it should be noted that some of these features may also be related to Precambrian topography rather than actual faulting.

The interpreted faults were depth converted and an attempt was made to interpret them in a three-dimensional (3D) space; however, given the nature and geometry of 2D surface seismic data, the 3D fault interpretation was highly uncertain and inconclusive. The future 3D seismic survey will provide more detail on 3D geometry (length, displacement etc.) of these minor faults. The layout of the 3D seismic survey is currently being designed to obtain full fold data over the predicted extent of the CO<sub>2</sub> plume after 30 years of injection and a 10 year PISC period (Attachment 7: Testing And Monitoring, 2022).

Some of the interpreted features appear to extend into the Mt. Simon Sandstone and have a maximum throw of approximately 42 ft. Uncertainties associated with these features include:

- Whether the features are minor faults or related to Precambrian topography
- Locations of these fault planes in 3D space

The Trenton Limestone and Eau Claire Formation reflectors are a constant throughout the area with no evidence of faulting (Figure 19 to Figure 22). Based on interpretations of this data the minor faults identified are not expected to act as conduits through the confining zone and USDWs will not be endangered.

At this time, no studies have been completed into the sealing capacity of these faults as they do not transect the confining zone. After the project acquires a baseline 3D surface seismic survey, if it becomes apparent that the minor faults do transect the confining zone the sealing capacity of the faults will be assessed at that time.

The project also plans to acquire a baseline 3D surface seismic survey that will be used to:

- Evaluate the properties of the injection zone and confining zone away from the project wells,
- Further characterize the potential faults in the Precambrian basement within the AoR, and
- Characterize Precambrian basement topography.

The data gathered during the pre-operational phase of the project will be used for geomechanical modeling. The geomechanical modeling will help determine if the minor faults identified in the surface seismic data are stable or whether they are critically stressed.

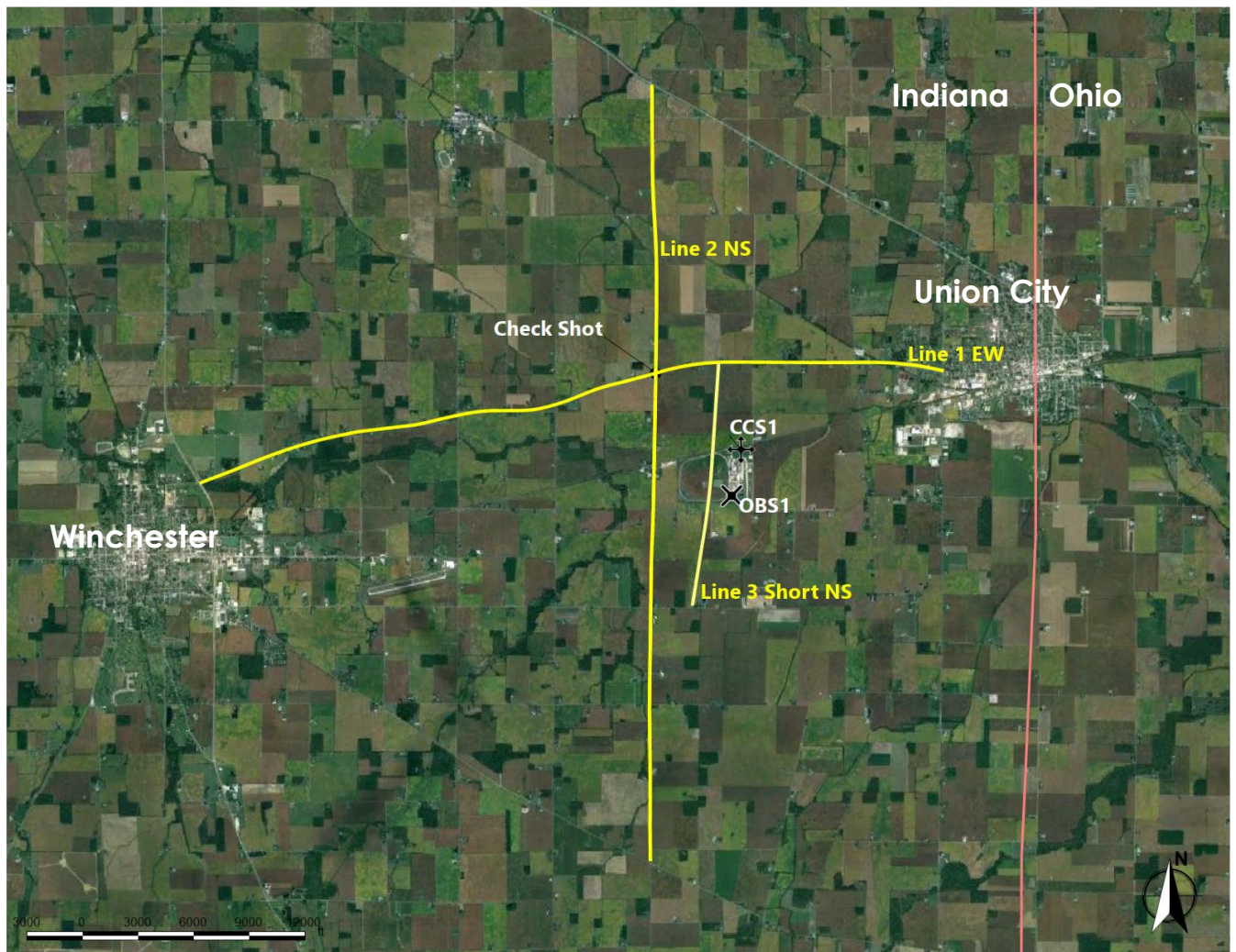


Figure 18 Seismic program location

Figure 19: Confidential Business Information: 2D seismic lines two-way time (TWT) in a 3D view

Figure 20: Confidential Business Information: 2D surface seismic Line 1 EW

Figure 21: Confidential Business Information: 2D surface seismic Line 2 NS

Figure 22: Confidential Business Information: 2D surface seismic Line 3 short NS

## 2.4 Injection and Confining Zone Details [40 CFR 146.82 (a)(3)(iii)]

### 2.4.1 Formation Tops and Mapping

The 2D seismic lines acquired for the project provide valuable site-specific information about the structural character of the Mt Simon Sandstone and Eau Claire Formation. The Trenton, Knox, Eau Claire, Mt Simon Sandstone and Precambrian horizon tops were first interpreted in the TWT domain and then depth converted so they could be incorporated into the geological structural model (Figure 19 to Figure 22).

Seismic well tie analysis (Figure 23) was completed to calculate the relationship between the TWT horizon interpretations and the interpreted structural surfaces in the depth domain. Ideally, the seismic data should be tied to a nearby well with good well log data; however, given the lack of well penetrations of the Mt. Simon Sandstone in the region, the closest well with reliable sonic and density data was 53 miles to the southeast (OH34017200040000). The well log data from this well was transposed into a synthetic well at the intersection of Line 1 EW and Line 2 NS and used to generate a synthetic seismogram. The synthetic seismogram was used to tie the well log data in depth and the 2D surface seismic data in TWT. Once this relationship was established, the interpretations of the horizons in TWT were converted to the depth domain and integrated into the structural framework model of the local area.

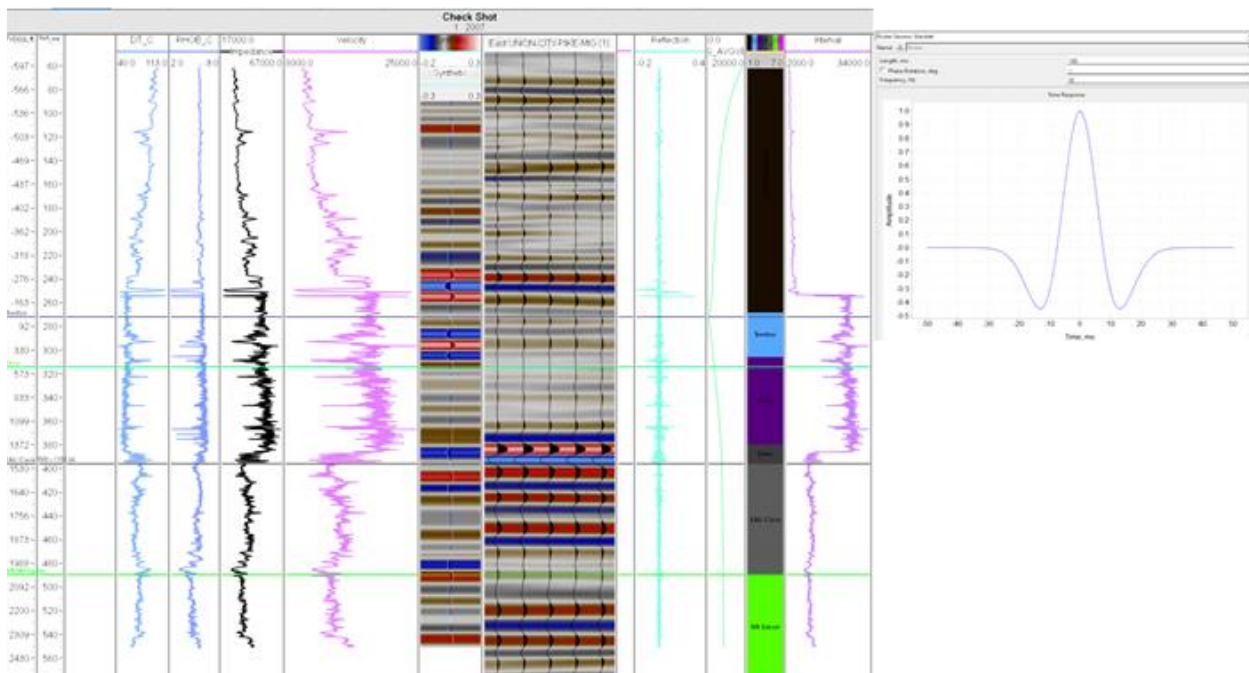


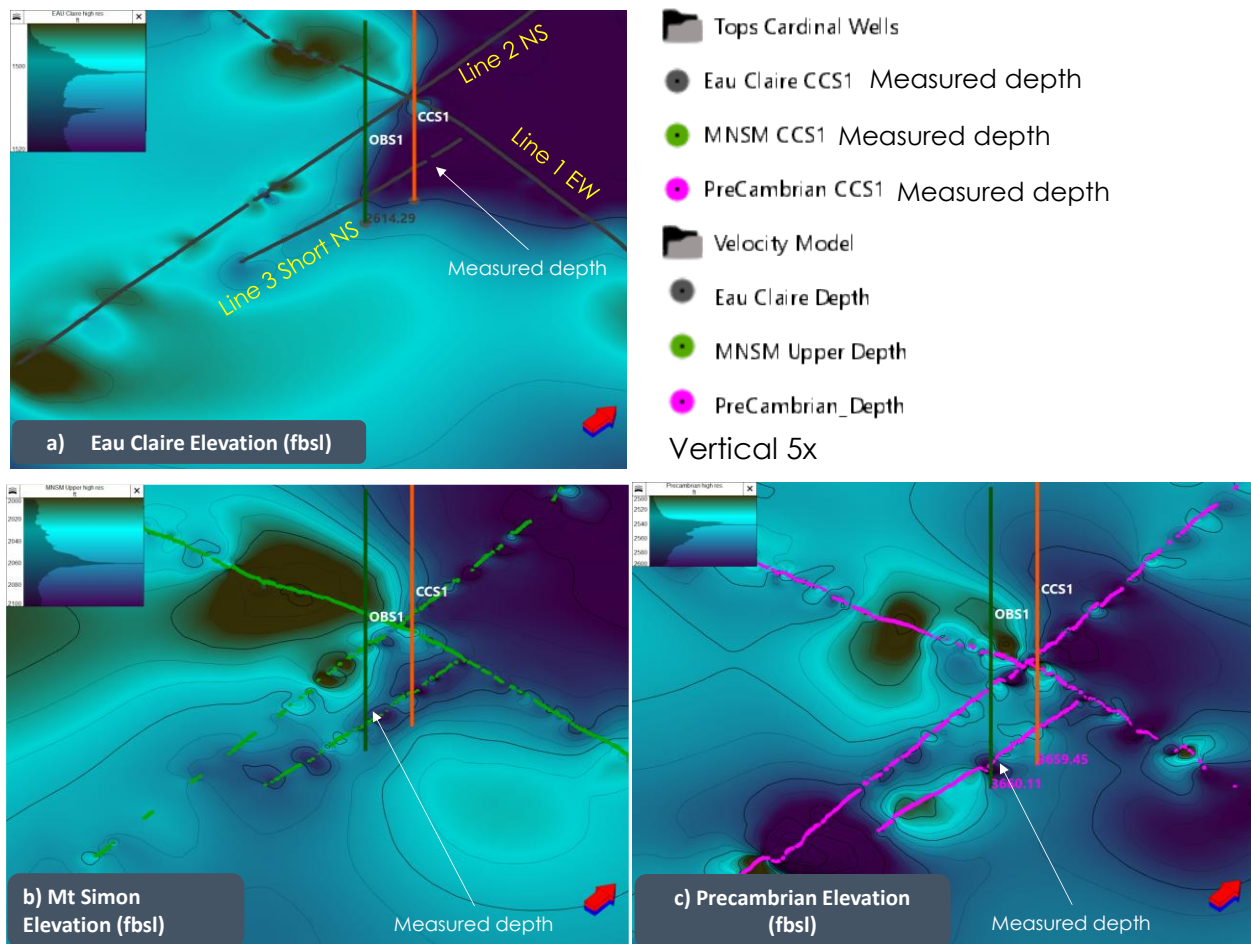
Figure 23: Seismic well tie

The convergent interpolation method was able to interpolate the details of the seismic interpretation between the seismic lines with the well tops. Horizons between the seismic interpretable horizons were generated using convergent interpolation and were matched to seismic interpretable horizons.

There is some uncertainty in the precision in the depth conversion due to the offset of the well data; however, the character of the seismic lines shows a relative consistency in the thickness of the Mt Simon Sandstone injection zone and Eau Claire confining zone. When the project

acquires a 3D surface seismic survey and drills the first well at the site, this relationship will be re-assessed and the current uncertainties will be reduced substantially.

The well logs and the depth converted seismic horizons were used to generate structural surfaces for the Eau Claire, Mt Simon Sandstone, and Precambrian horizons (Figure 24 to Figure 27). Thickness maps for the Eau Claire Formation and Mt Simon Sandstone are presented in (Figure 28).



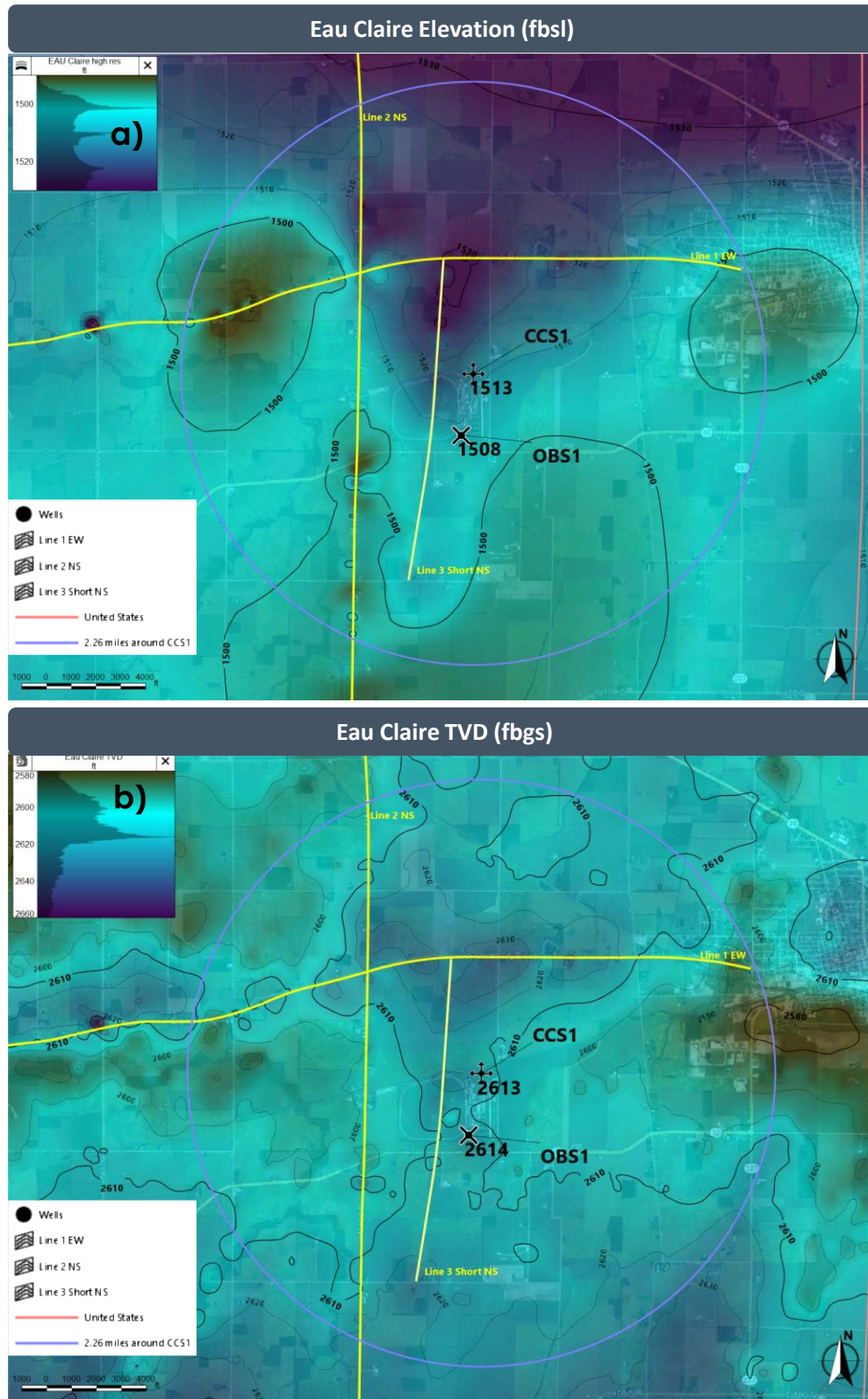
**Figure 24: Seismic based local elevation maps. A) Eau Claire, b) Mt Simon Sandstone, c) Precambrian**

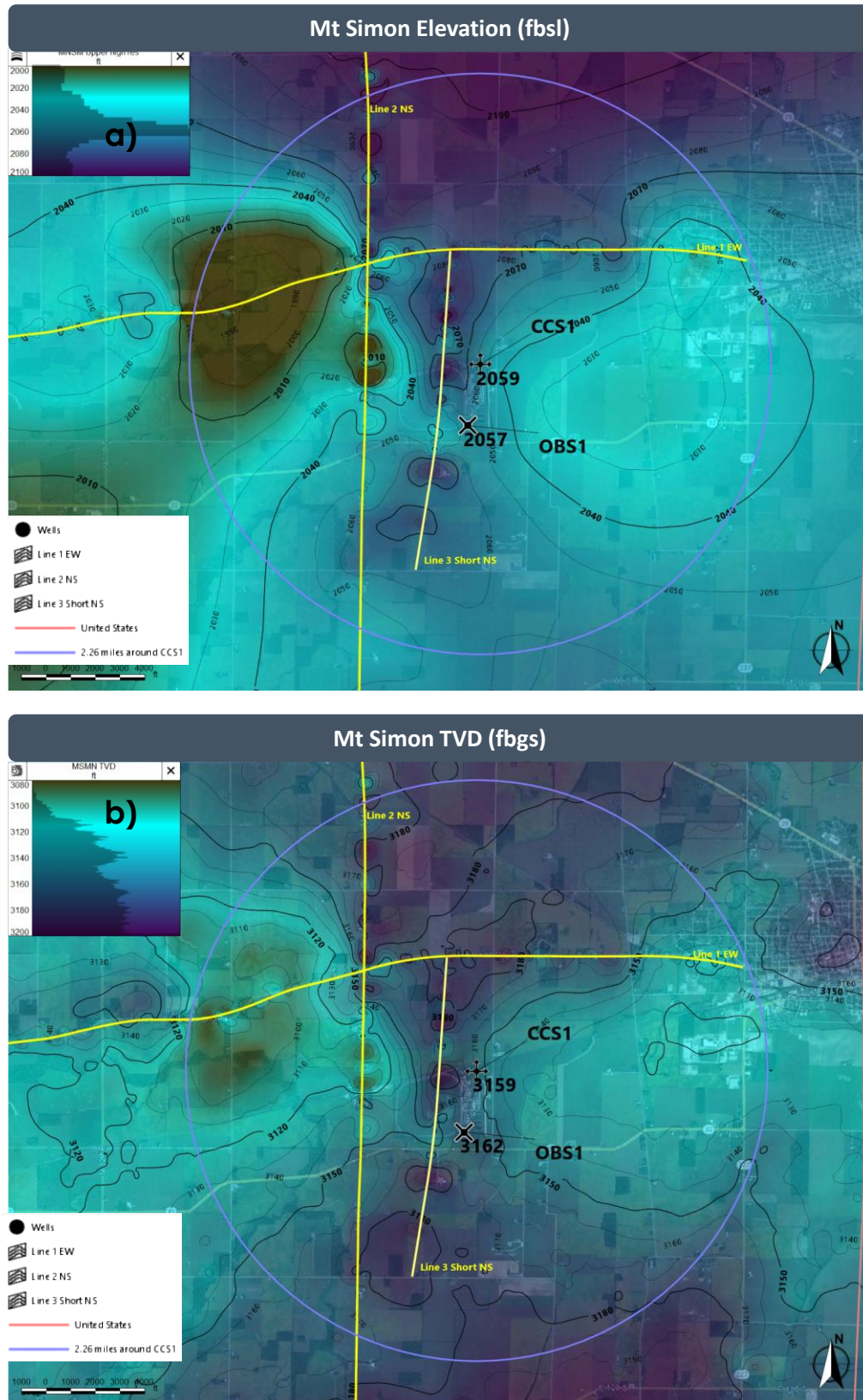
The 2D seismic lines show variations in elevation of 41 ft were interpreted at the top of the Eau Claire Formation horizon, and the top of the Mt. Simon Sandstone shows elevation variations of 95 ft (Figure 25 and Figure 26). Elevation variations of up to 138 ft within the Precambrian basement (Figure 27). The topographic details of these hills and valleys between the lines will remain uncertain until a baseline 3D seismic survey is acquired and interpreted.

The elevation variations interpreted in the horizons are minor and do not show any significant thinning of the injection or confining zones. CO<sub>2</sub> plume development is expected to be controlled in part by heterogeneities in the injection zone as opposed to any structural features or

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stratigraphic thinning. The confining zone will provide a thick, consistent barrier to upward migration of injection zone fluids over time.





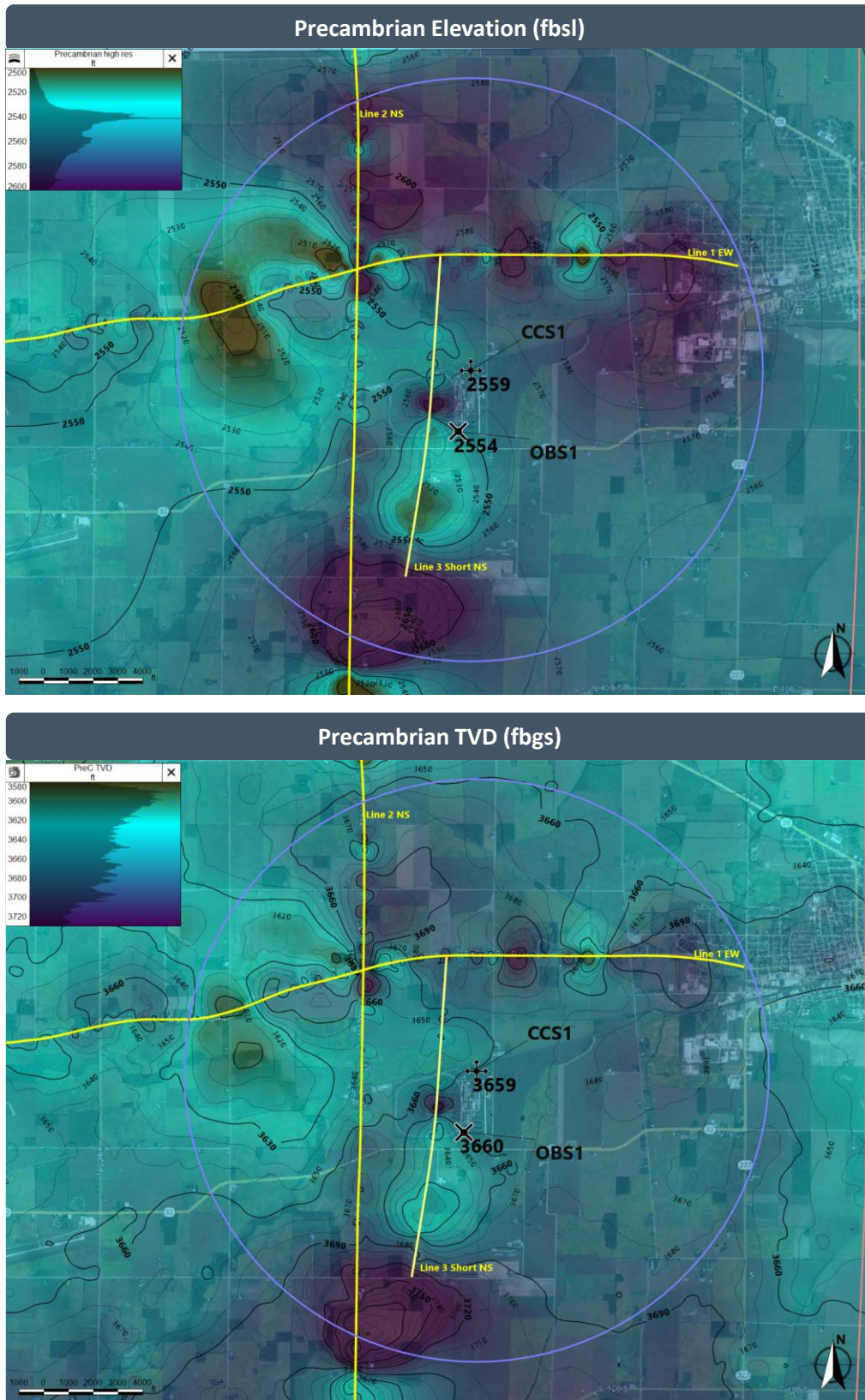


Figure 27: AoR Precambrian lower confining zone surface a) elevation and b) TVD

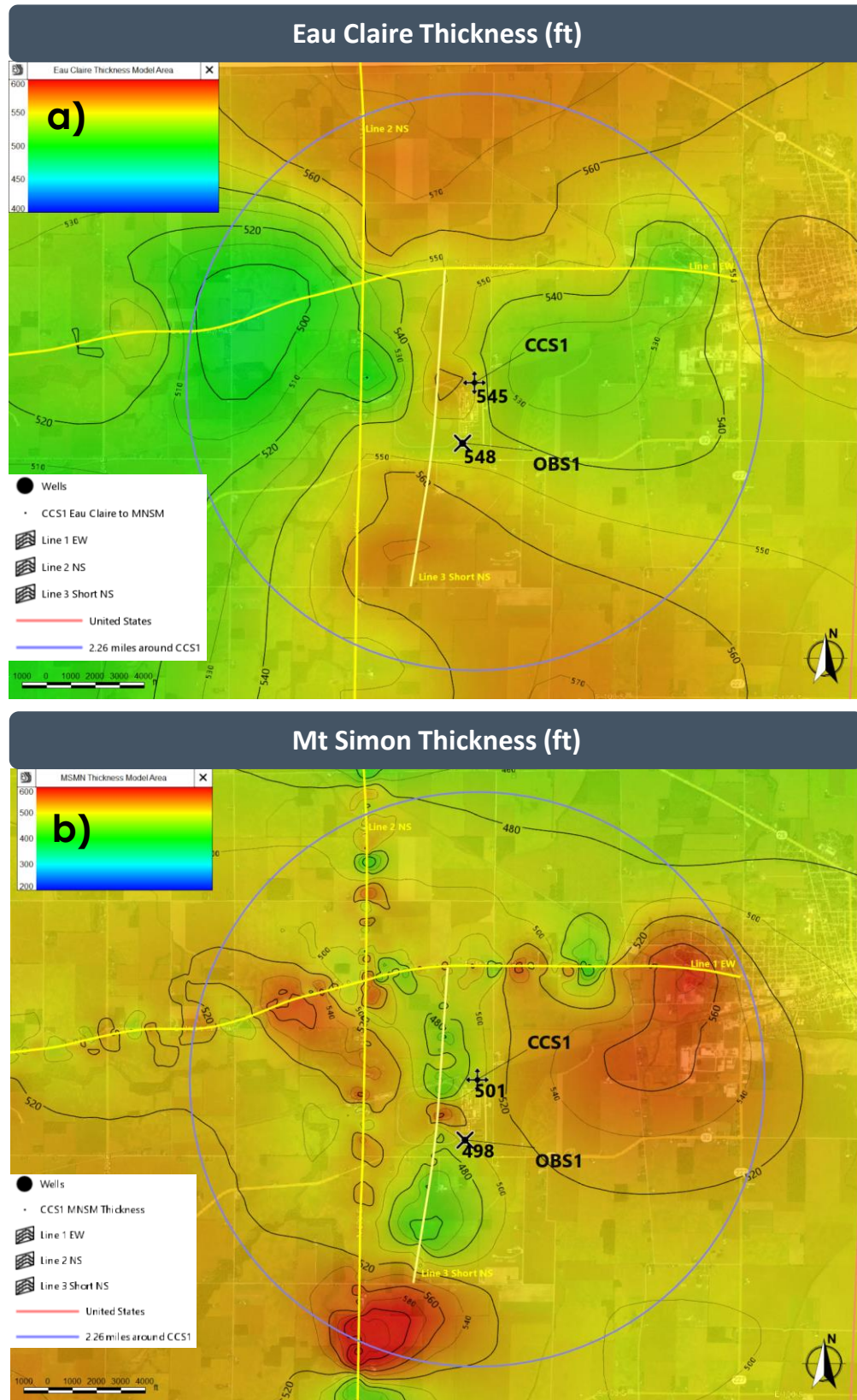


Figure 28: AoR Thickness Maps a) Eau Claire confining zone and b) Mt Simon Sandstone injection zone

### 2.4.2 Porosity and Permeability

Three wells have provided significant data to assist in the characterization of the injection and confining zones: IN133540 and two Class I injection wells in Ohio (Figure 29). These wells have well logs, core, and fluid injection data covering the complete Mt. Simon Sandstone section. The data from these wells represent the nearest analog for how the injection and confining zones may perform and are believed to be reasonably representative of the injection zone at the project site. The data from these wells were used as a calibration point for the petrophysical analysis of eight wells in the region (Figure 29).

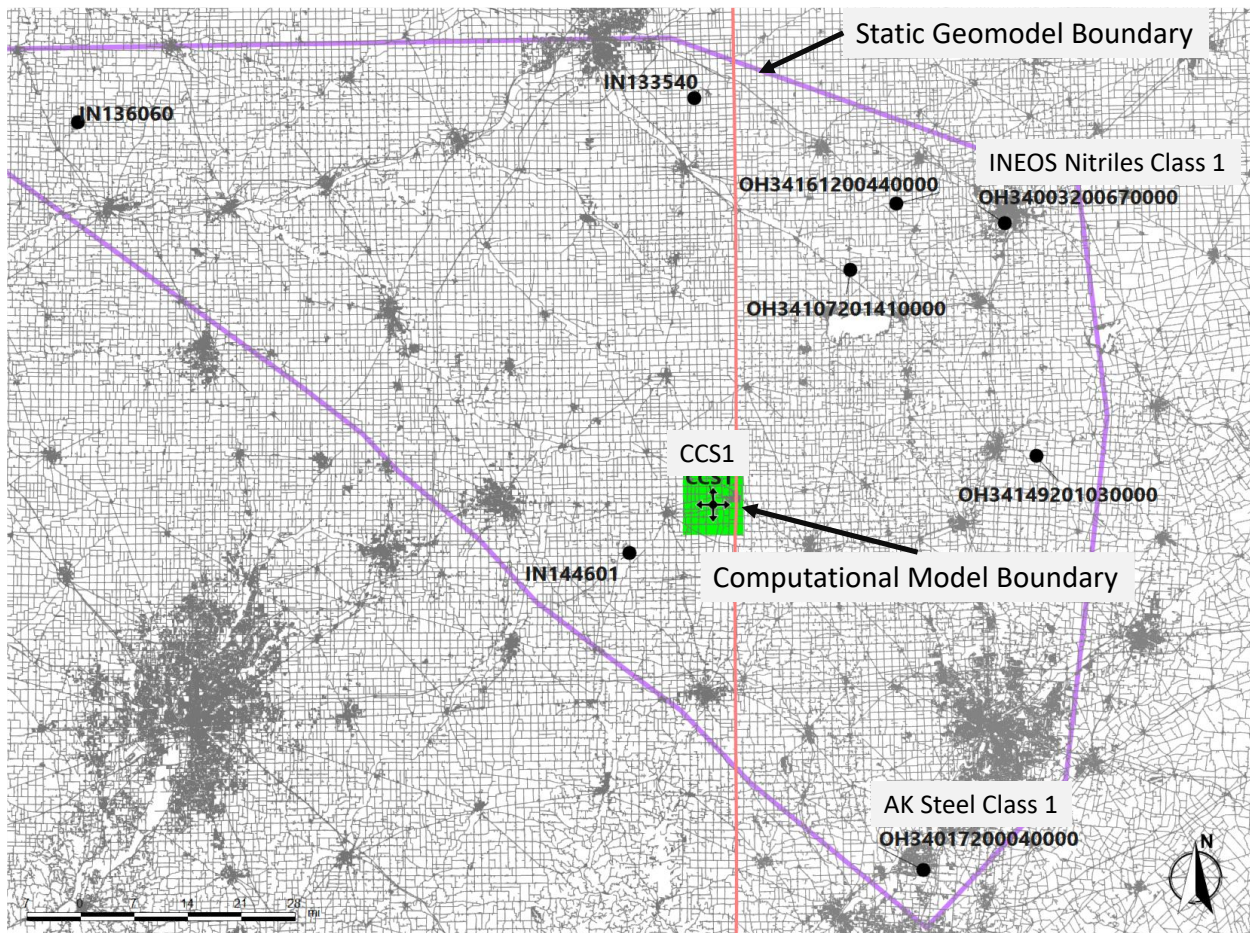


Figure 29: Wells used for injection zone, confining zone and petrophysical analysis

#### 2.4.2.1 Mt. Simon Sandstone

The Mt. Simon Sandstone lies unconformably upon the Middle Run Formation. There is an abrupt change from the poorly sorted, heterogenous, angular, well cemented rocks of the Middle Run Formation and the lighter, homogenous, less cemented partially friable basal Mt. Simon Sandstone (Saeed, 2002). The Mt. Simon Sandstone can be sub-divided into two lithologic packages related to depositional environment. The lower portion likely represents a fluvial-deltaic environment with increasing marine influence towards the top of the sequence. The upper portion represents a transitional marine sequence characterized by the presence of glauconite.

Section 2.1.1.1 discusses the regional mineralogy and petrology of the Mt. Simon Sandstone in detail. The Mt. Simon Sandstone contains feldspar, potentially carbon cement, and clay minerals. Some of these minerals are reactive with CO<sub>2</sub>. And it is expected that there will be changes to the aqueous geochemistry of the Mt. Simon Sandstone fluids once CO<sub>2</sub> injection commences. Site specific information about the injection zone will be acquired when the project wells are drilled through the pre-operational testing program that will include well logging, fluid sampling, and core acquisition and analysis (Attachment 5: Pre-Op Testing Program, 2022). This data can be used for geochemical modeling that will predict the geochemical reactions likely to occur in the injection zone with the introduction of CO<sub>2</sub> to the formation.

Table 6 summarizes the porosity and permeability values for the Mt. Simon Sandstone that were derived from the AK Steel, INEOS (BP Lima) Nitrile, and 133540 wells (AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021; INEOS (BP Lima) Nitriles, August 22, 2016). The values in the table were derived from a combination of core and reservoir testing. These values were incorporated in the static model developed for the project (Attachment 2: AoR and Corrective Action, 2022).

**Table 6: Summary of porosity and permeability values for the Mt. Simon Sandstone from three wells in the region**

Well	Porosity Range (%)	Permeability Range Millidarcy (mD)
AK Steel	Core: 4.9 – 21.1, Avg = 13.5 Well Log: 5 – 21	0.1 – 8520
INEOS (BP Lima) Nitrile	2.6 – 20.8	0.0005 – 645
133540	Core: Avg = 8.5	

Well logs and core analyses completed as part of the pre-operational testing program will be used to further characterize the porosity and permeability of the injection zone (Attachment 5: Pre-Op Testing Program, 2022). The baseline 3D surface seismic data will be calibrated to the well data and used for inversion analysis. This will allow the project to characterize variations in porosity and lithology away from the project wells for the entire injection zone over the imaging area of the 3D surface seismic data volume.

Computational modeling has confirmed that the injection zone will have the capacity to store 450 kt/ yr and a total of 13.5 million tons of CO<sub>2</sub> over a 30-year injection period (Attachment 2: AoR and Corrective Action, 2022).

#### *2.4.2.2 Eau Claire Formation*

Section 2.1.1.4 discusses the regional mineralogy and petrology of the Eau Claire Formation in detail. The Eau Shale includes interbedded green and reddish-brown glauconitic shales. The Eau Claire Silt is composed of glauconitic siltstone and very fine-grained sandstone. The Mt. Simon Sandstone is transitional with the base of the Eau Claire Formation, and CO<sub>2</sub> is expected to migrate into this part of the Eau Claire Formation over time.

The minerals in the Eau Claire formation are not expected to be reactive with CO<sub>2</sub> over time. However, the site specific information about the confining zone that is acquired when the project wells are drilled through the pre-operational testing program will be used for geochemical modeling to establish whether or not prolonged contact with CO<sub>2</sub> will impact the integrity of the confining zone (Attachment 5: Pre-Op Testing Program, 2022).

In 1988, the ODNR drilled a stratigraphic test in Warren County to investigate the presence of Precambrian rifting. The well substantiated the theory with the discovery of Precambrian aged sedimentary rocks. During detailed geologic analysis of this well, three facies were identified from thin section within the Eau Claire Formation (Table 7).

**Table 7: Eau Claire Formation facies identified in the Warren County stratigraphic test well**

<b>Facies</b>	<b>Depth (ft)</b>	<b>Effective Porosity (%)</b>	<b>Permeability Range (mD)</b>
Bioclastic Oolitic Packstone/Grainstone	One sample: 2,690.8	0.3	
Silty Dolomite/Dolomitic Siltstone	Eight samples: 2,714.6 – 3,015.2	3.4	Less than 0.01 mD detection limit
Glauconitic Fine-Grained Sandstone	Five samples: 3,049 – 3,149.9 3,107 – 3,108		Vertical: 0.86 Horizontal: 0.86

The sample in the Glauconitic Fine-Grained Sandstone facies at 3,107 – 3,108 ft showed different vertical and horizontal air permeabilities showing that the Eau Claire Formation is anisotropic at this interval (Table 7). An interval with a relatively high horizontal permeability provides a valuable buffer to attenuate possible fluid pressure buildup. According to the report on thin section examination of the test hole core, porosity in the sample 3,107 ft— 3,108 ft has developed due to dissolution of dolomite. Secondary fracture porosity was not noted (Kemron Environmental Services, Inc, 2018).

Porosity and permeability measurements taken from INEOS (BP Lima) Nitriles facility provide site-specific information about the regional permeability of the Eau Claire Formation and are considered correlative to the project site. Porosities measured from core samples range from 0.1% to 10.1%, and permeabilities measured in the cores range from 0.000017 mD to 0.25 mD (Table 8).

**Table 8: INEOS (BP Lima) facility Eau Claire porosity and permeability (INEOS USA, LLC, 2015)**

<b>POROSITY AND PERMEABILITY OF THE ARRESTMENT INTERVAL (2430 Feet – 2640 Feet)</b>			
<b>FORMATION</b>	<b>MODELING LAYER DEPTH</b>	<b>POROSITY (%)</b>	<b>PERMEABILITY (md)</b>
Eau Claire	EC <sub>6</sub> 2430' 2490'	3 – 5.4	0.0012 – 0.0040
	EC <sub>5</sub> 2548'	0.1 – 0.2	0.000017 – 0.00033
	EC <sub>4</sub> 2617'	0.2 – 2.7	0.000227 – 0.00131
	EC <sub>3</sub> 2640' 2676'	4.0 – 10.1	0.00047 – 0.25

Eau Claire Formation core permeability measurements taken from AK Steel disposal well also provide site-specific information about the regional permeability of the confining zone and are considered representative of the project site (Table 9). Fluid permeabilities measured in the cores range from  $3.43 \times 10^{-2}$  to less than  $1 \times 10^{-6}$  mD. Eight of the ten samples tested had no measurable fluid permeability.

**Table 9: AK Steel UIC Well1 Core Flow Study results for the Eau Claire Formation permeability (Kemron Environmental Services, Inc, 2018)**

SAMPLE NO.	DEPTH	VERTICAL PERMEABILITY TO WATER (MD)
1	2858.9-59.3	$3.43 \times 10^{-2}$
2	2863.0-63.5	$1.39 \times 10^{-4}$
3	2869.5-70.0	$<1.00 \times 10^{-6}$
4	2870.0-87.5	$<1.00 \times 10^{-6}$
5	2875.0-75.6	$<1.00 \times 10^{-6}$
6	2876.4-76.8	$<1.00 \times 10^{-6}$
7	2877.4-77.8	$<1.00 \times 10^{-6}$
8	2878.3-78.7	$<1.00 \times 10^{-6}$
9	2879.0-79.6	$<1.00 \times 10^{-6}$
10	2880.4-80.8	$<1.00 \times 10^{-6}$

Core permeability measurements taken from AK Steel UIC Well No. 1, DGS 2627 and Betty Leuenberger No. 1 well show that the effective vertical permeability of the Eau Claire Formation does not exceed  $10^{-2}$  mD and is more likely to be  $1 \times 10^{-4}$  mD or less. The effective vertical permeability of  $10^{-1}$  mD assigned to the arrestment interval in the model builds in an additional margin of safety of one to three orders of magnitude (Kemron Environmental Services, Inc, 2018).

Well logs and core analyses completed as part of the pre-operational testing program will be used to further characterize the porosity and permeability of the confining zone (Attachment 5: Pre-Op Testing Program, 2022). The baseline 3D surface seismic data will be calibrated to the well data and used for inversion analysis. This will allow the project to characterize variations in porosity and lithology away from the project wells for the entire confining zone over the imaging area of the 3D surface seismic data volume.

The capillary pressure of the confining zone is not known, but it is not considered to be a significant factor in confining zone integrity. The permeability of the confining zone is very low and is not likely to allow any migration of CO<sub>2</sub> vertically. The capillary pressure and permeability of the Eau Claire Shale will be measured as part of the core analysis completed as part of the pre-operational testing program (Attachment 5: Pre-Op Testing Program, 2022).

Geomechanical modeling of the confining zone integrity was completed using step-rate test results from the INEOS (BP Lima) Nitriles disposal site (INEOS (BP Lima) Nitriles, August 22, 2016). This modeling demonstrated that the increase in effective stress on the confining zone associated with injection rates of 400 kt/yr would not be large enough to open any existing fractures in the confining zone. Even if the project were to increase the injection rate to 1.9

Million Metric Tons per Year (MMT/yr) the increases in effective stress would not be enough to open existing fractures.

#### 2.4.2.3 Knox Formation

The Knox Dolomite is a potential secondary confining zone for the project and has been identified as a potential above confining zone (ACZ) monitoring interval. It is primarily a dolomite that is composed of white to brown, very fine to coarse-grained, crystalline to sugary dolomite, containing pyrite, white and light blue oolitic chert, and dolomite rhombs with fossil fragments. Portions of the Knox Dolomite are vuggy and thus the unit contains some intervals capable of acting as buffering units. Occasional frosted subangular quartz grains cemented with calcium carbonate are noted, as are glauconitic siltstones and dark gray to black shale (Kemron Environmental Services, Inc, 2018).

At the INEOS (BP Lima) Nitriles disposal site, the Knox Dolomite has been identified as the confining zone. Core-derived porosity and permeability in the lower one third of the Knox Dolomite indicate that porosity ranges from less than 0.1 to 14.5 percent and permeability from 0.00005 md to 24.1 md (Table 10). The lower values correspond to the siltstones, shales, and dense dolomites while the upper values correspond to the vugular and sandy dolomites.

**Table 10: Knox Dolomite porosity and permeability from the INEOS (BP Lima) Nitriles disposal site (INEOS USA, LLC, 2015)**

FORMATION	MODELING LAYER DEPTH	POROSITY (%)	PERMEABILITY (md)
Knox Dolomite	2100 KD <sub>2</sub> 2310	Ave 0.8	Ave. 0.00029
	KD <sub>1</sub> 2430	5.1 – 14.5 Ave 7.8	Ave 6.3 0.01 – 24.1

Calculations made using AK Steel #1 well log show the Knox Dolomite porosity ranges from 0% to 4%. A few thin beds that are approximately 3 to 5 ft thick with porosities of approximately 9% are scattered throughout the formation (Kemron Environmental Services, Inc, 2018).

Well logs acquired as part of the pre-operational testing program will be used to further characterize the porosity and permeability of the Knox Group formations and verify that some of the formations will provide an effective secondary confining interval (Attachment 5: Pre-Op Testing Program, 2022). The well logs are expected to identify a porous, permeable interval under the Knox Unconformity that can be used as a ACZ monitoring zone. The baseline 3D surface seismic data will be calibrated to the well data and used for inversion analysis. This will allow the project to characterize variations in porosity and lithology away from the project wells for the Knox Group formations over the imaging area of the 3D surface seismic data volume.

## 2.5 Geomechanical and Petrophysical Information [40 CFR 146.82 (a)(3)(iv)]

### 2.5.1 Geomechanics

Simple geomechanical modeling was completed to test the integrity of the confining zone. The computation modeling results were used as input to for the geomechanical modeling (Attachment 2: AoR and Corrective Action, 2022). Geomechanical information for the Eau Claire and Mt. Simon formations was found in the INEOS (BP Lima) Class I permit (Table 11). The average values were used to model the Eau Claire confining zone integrity given the anticipated injection rate of 400 kt/Y. In addition, step-rate test data and information on the breakdown, propagation, and closure gradients were obtained from this permit to support the modeling of the confining zone integrity (Figure 30 and Table 12).

**Table 11: Summary of Young's Modulus, Poisson's Ratio, and Bulk Compressibility values from the INEOS (BP Lima) Nitriles UIC permit (INEOS USA, LLC, 2015).**

Horizon	Young's Modulus (psi)	Poisson's Ratio	Bulk Compressibility (1/psi)
Cincinnati Group	2.17E+06	0.14	5.35E-07
Trenton	6.51E+06	0.06	3.19E-07
Black River	6.88E+06	0.09	3.48E-07
Knox (KD2)	1.06E+07	0.10	2.67E-07
Knox (KD1)	5.39E+06	0.19	3.59E-07
Knox Average	7.67E+06	0.14	3.06E-07
Eau Claire (EC4)	1.78E+06	0.01	1.41E-07
Eau Claire (EC3)	4.19E+06	0.11	5.40E-07
Eau Claire (EC2)	3.61E+06	0.25	5.17E-07
Eau Claire (EC1)	2.65E+06	0.11	4.25E-07
Eau Claire Average	5.65E+06	0.12	5.60E-07
Mt. Simon (MS3)	2.62E+06	0.11	1.06E-06
Mt. Simon (MS2)	2.50E+06	0.17	6.95E-07
Mt. Simon (MS1)	2.39E+06	0.13	1.06E-06
Mt. Simon Average	2.46E+06	0.14	1.07E-06
Middle Run	5.26E+06	0.11	7.85E-07

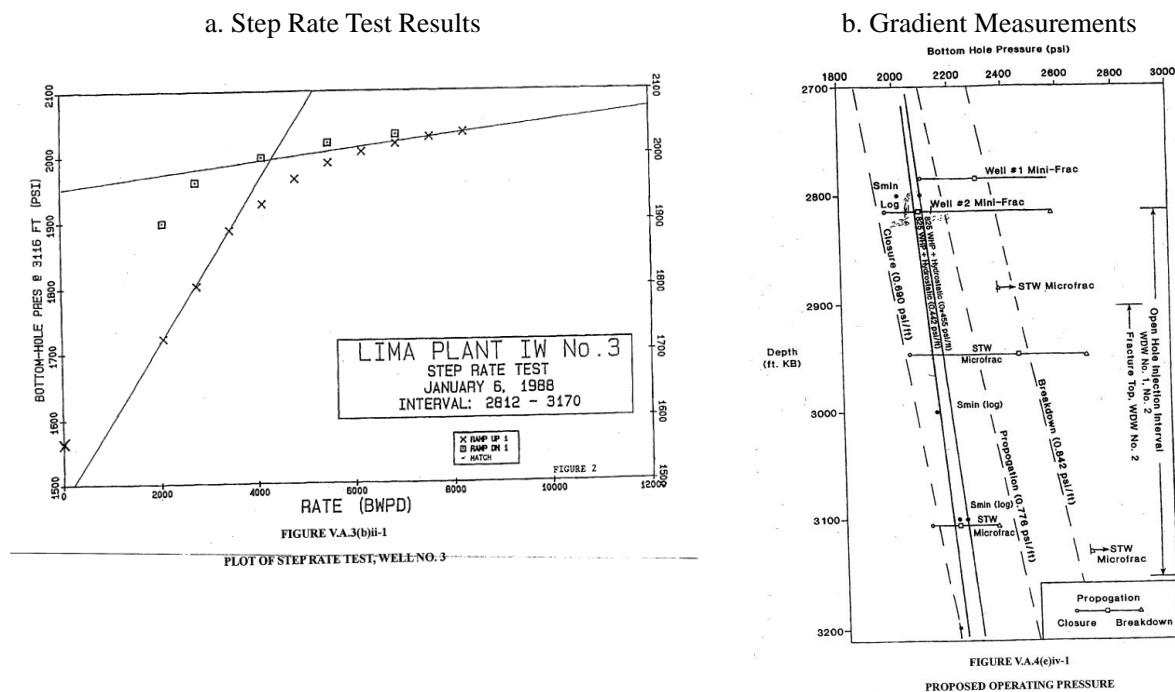


Figure 30: Geomechanical data from the INEOS (BP Lima) Nitriles disposal site. A. step rate test results b. breakdown, propagation, and closure gradients (INEOS (BP Lima) Nitriles, August 22, 2016)

Table 12: Summary of breakdown, propagation, and closure gradients and pressures for the top of the Mt. Simon Sandstone at 3,100 ft based on the INEOS (BP Lima) Nitriles permit (INEOS (BP Lima) Nitriles, August 22, 2016)

	Gradient (psi/ ft)	Pressure (psia)
Breakdown	0.842	2,610
Propagation	0.776	2,406
Closure	0.690	2,139

The geomechanical modeling predicted an initial mean effective stress of 795 and 966 psi for the tops of the Eau Claire Formation and Mt. Simon Sandstone, respectively. It also predicts a maximum increase in pore pressure of 378 psi at the top of the Mt. Simon Sandstone, which is below the pressures required to open fractures within the Eau Claire Shale. It also showed no evidence of CO<sub>2</sub> migration into the Eau Claire Shale after 30 years of injection. Even at injection rates of 1.9 MMT/yr, the decrease in effective stress on the confining zone was not enough to open existing fractures.

During the pre-operational phase of the project, a variety of site-specific data from the confining and injection zones will be acquired in the project wells to support further geomechanical modeling. These data include:

- Caliper and image logs,
- Triaxial testing to establish geomechanical parameters such as rock strength, Young's Modulus, Poisson's Ratio, and fracture gradient,
- Step-rate testing.

## 2.5.2 *Petrophysics*

Petrophysical analysis of the Eau Claire, Mt Simon, and Precambrian formation was completed on eight wells in the region (Figure 29). Log ascii standard (LAS) files and routine core data was acquired from the Indiana Geological & Water Survey and Ohio Division of Oil & Gas public data sources. These wells were the only wells within the Mt Simon Sandstone that had reliable data. The vintages of the data from these wells range from 1966 -1985, as a result data quality is variable. The log data associated with these wells is shown in Table 13.

Aptian Technical Ltd. and CORE Petrophysical Consulting Inc completed the petrophysical analysis using PowerLog and Geology respectively.

**Table 13: Available well logs used for petrophysical analysis**

Wells	Year	Logs
IN144601	1966	Gamma, Neutron Porosity, Density,
IN133540	1968	Gamma, Caliper, Med Induction, Neutron Porosity, 365 Core Plugs (Porosity, horizontal Max Perm (kmax), perm vertical/perm horizontal) kv/kh)
OH34017200040000	1967	Gamma, Sonic, Neutron Porosity, Density Porosity, Density, 85 Core Plugs (Porosity, kmax, kv/kh)
OH34161200440000	1973	Gamma, Sonic, Neutron Porosity, Density,
IN136060	1967	Gamma, Neutron Porosity, 575 Core Plugs (Porosity, komax, kv/kh)
OH34003200670000	1968	Gamma, SP, Caliper, Deep Induction, Med Induction, Density, 47 Core Plugs (Porosity, kmax, kv/kh)
OH34149201030000	1985	Gamma, Caliper, Sonic, Deep Induction, Neutron Porosity, Density, Photoelectric,
OH34107201410000	1971	Gamma, Caliper, Neutron Porosity, Density Porosity, Density,

Core and log data were calibrated to Class I water disposal wells at AK Steel and INEOS (BP Lima) and used as a primary input to the geomodel (Figure 7). These Class I wells have years of injection volumes and significant geologic and reservoir data sets, all of which were used to model the injection and confining intervals. Using the Class I wells as analogs petrophysical analysis was completed on these and other well logs. Histograms and cross plots were made using this data which enabled better analysis of wells which did not have core data and improved the geologic model.

The petrophysical analysis was completed to estimate the facies, porosity, and permeability of the confining and injection zones. Core data was available in four of these wells and was used to guide the petrophysical calculations. Preprocessing work was required to get the raw log data ready for the petrophysical calculations. This included a depth shift of curves, unit correction for consistency, and creation of synthetic curve data to remedy intervals of bad data and missing logs.

While deriving porosity and permeability curves for these wells, the core (porosity and permeability) plug measurements were used as a calibration point. Core measured porosity and permeability values were very erratic with high and low values that occurred at specific depth ranges. This may indicate the presence of natural fractures. A relationship with the gamma,

neutron porosity, sonic, and density logs was used to derive the petrophysical properties for the eight wells which included:

- Volume Clay (VCLAY),
- Facies
  - Sandstone 1 (Mt Simon Sandstone)
  - Sandstone 2 (Mt Simon Sandstone)
  - Silty sandstone (Eau Claire and Davis)
  - Shale (Eau Claire)
  - Limestone (Davis and small amounts in Eau Claire)
  - Dolomite (Davis)
  - Precambrian (Precambrian)
- Mineralogy (where the data quality was reliable)
  - Volume Shale
  - Volume Quartz
  - Volume Limestone
  - Volume Dolomite
  - Volume Sphalerite
- Effective Porosity
- Permeability

Figure 31 to Figure 34 show the results of the petrophysical analysis for IN 133540, the AK Steel, INEOS (BP Lima) Nitrile, and IN144601 wells. The porosity and permeability relationships were calculated for each facies type (Figure 35). The petrophysical results in the Precambrian basement were not considered reliable. The petrophysical log results were calibrated to core by adjusting the petrophysical model to align with the core data. The expected heterogeneities were resolved by establishing a best fit between input logs and output petrophysical logs (Table 13). The input core data showed the vertical anisotropy (kv/kh) to be about 5. The porosity and permeability relationships presented in Figure 35 were used to develop the static model (Attachment 2: AoR and Corrective Action, 2022).

The petrophysical calculations within the Eau Claire Formation and Mt Simon Sandstone show a reasonable estimate of porosity and permeability despite the vintage of the log data. The petrophysical analysis will be re-visited once the project acquires site-specific well logs and core data in the project wells (Attachment 5: Pre-Op Testing Program, 2022).

**Figure 31: Confidential Business Information: IN133540 input data and petrophysical analysis**

**Figure 32: Confidential Business Information: AK Steel input data and petrophysical analysis**

**Figure 33: Confidential Business Information: INEOS (BP Lima) Nitriles input data and petrophysical analysis**

**Figure 34: Confidential Business Information: IN144601 input data and petrophysical analysis**

**Figure 35: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey)**

## **2.6 Seismic History [40 CFR 146.82(a)(3)(v)]**

The project site is located in an area of the United States which is classified by the Federal Emergency Management Agency (FEMA) as earthquake hazard category A/White where there is a very small probability of experiencing damaging earthquake effects (Figure 36 and Table 14). The United States Geological Survey (USGS) keeps an up-to-date online library of earthquakes and seismic events that have occurred in the United States from 1800 to the present day (USGS, 2022). Figure 37 and Table 15 display the epicenter of each of the 2.5 or greater magnitude earthquakes (or seismic events) recorded within a 100-mile radius of the project site from 1800 to February 2022 (USGS, 2022). In addition, Figure 38 is a merged map of earthquake epicenters and bedrock structural features from the Indiana Geological and Water Survey (IGWS) and the ODNR Division of Geological Survey.

All the earthquakes since 2004 have had a magnitude of less than four. The nearest epicenter to the project was approximately 20 miles north. The event occurred in 1990 and was 3.0 magnitude. The most recent earthquake occurred on June 12, 2015, approximately 53 miles from the project site and had a magnitude of 2.6. The largest recorded earthquake (5.4 magnitude) within 100 miles occurred on March 9, 1937 and had a magnitude of 5.4; it was approximately 36 miles from the project site. No earthquakes have been identified that have an epicenter within the project AoR.

The Hoosier #1 Project is located in an area with minimal earthquake activity, which suggests that there are no major structural faults in proximity to the project site. Section 2.1.2 discusses the status of the questionable Auglaize Fault; this fault is not expected to present a hazard to the project.

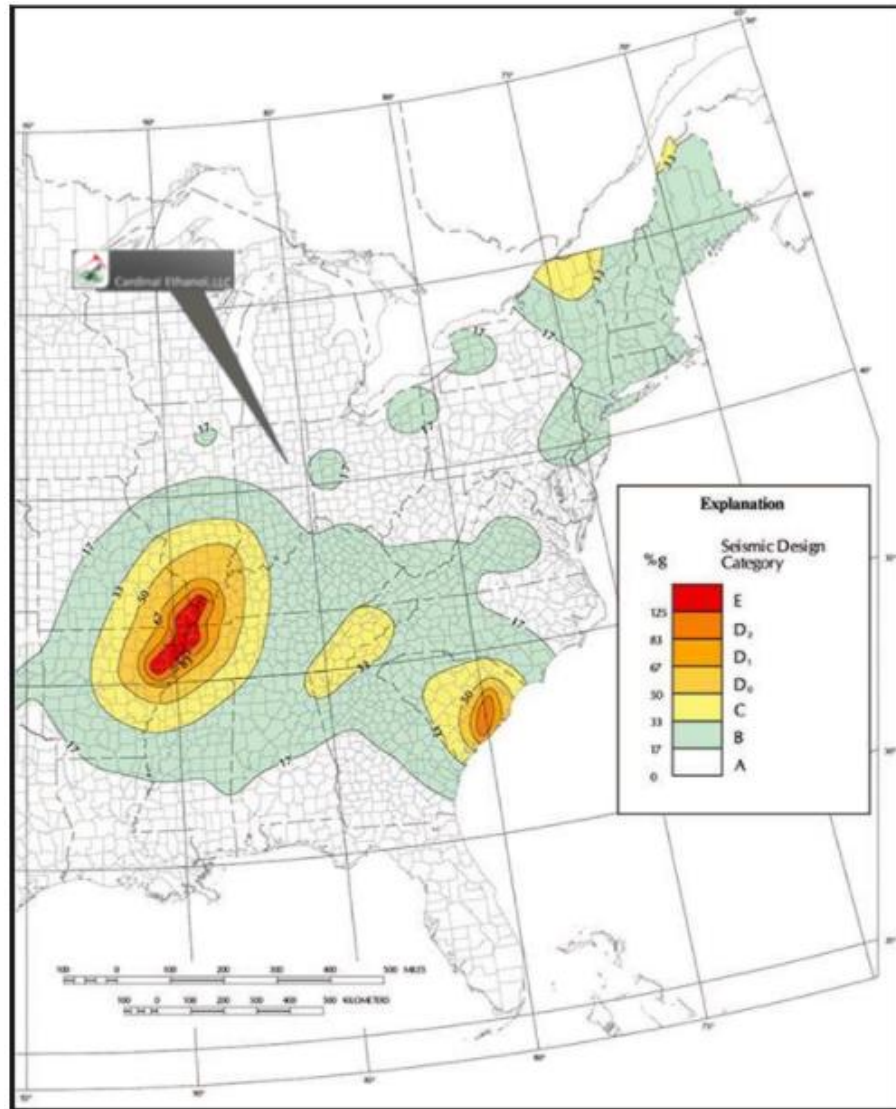


Figure 36: FEMA Earthquake Hazard Map (FEMA, 2022)

**Table 14: FEMA Earthquake Hazard Level (FEMA, 2022).**

<b>SDC/Map Color</b>	<b>Earthquake Hazard</b>	<b>Potential Effects of Shaking</b>
A/White	Very small probability of experiencing damaging earthquake effects.	
B/Gray	Could experience shaking of moderate intensity.	Moderate shaking—Felt by all, many frightened. Some heavy furniture moved; a few instances of fallen plaster. Damage slight.
C/Yellow	Could experience strong shaking.	Strong shaking—Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built structures.
D/Light Brown D1/Darker Brown D2/Darkest Brown	Could experience very strong shaking (the darker the color, the stronger the shaking).	Very strong shaking—Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures.
E/Red	Near major active faults capable of producing the most intense shaking.	Strongest shaking—Damage considerable in specially designed structures; frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations. Shaking intense enough to completely destroy buildings.

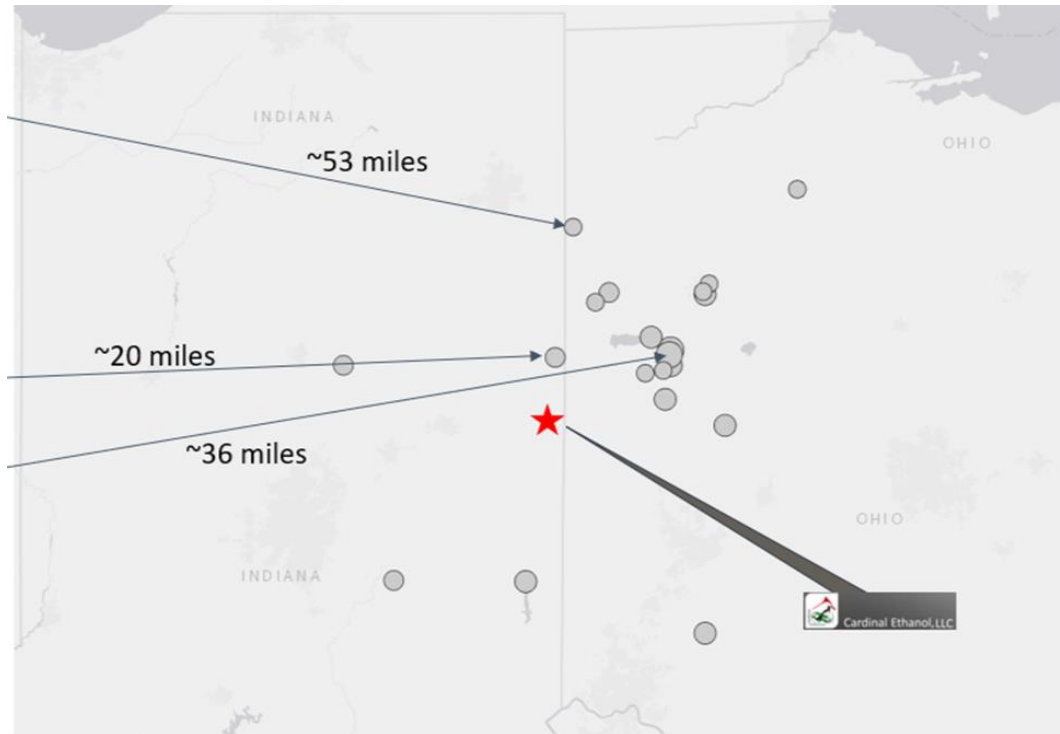
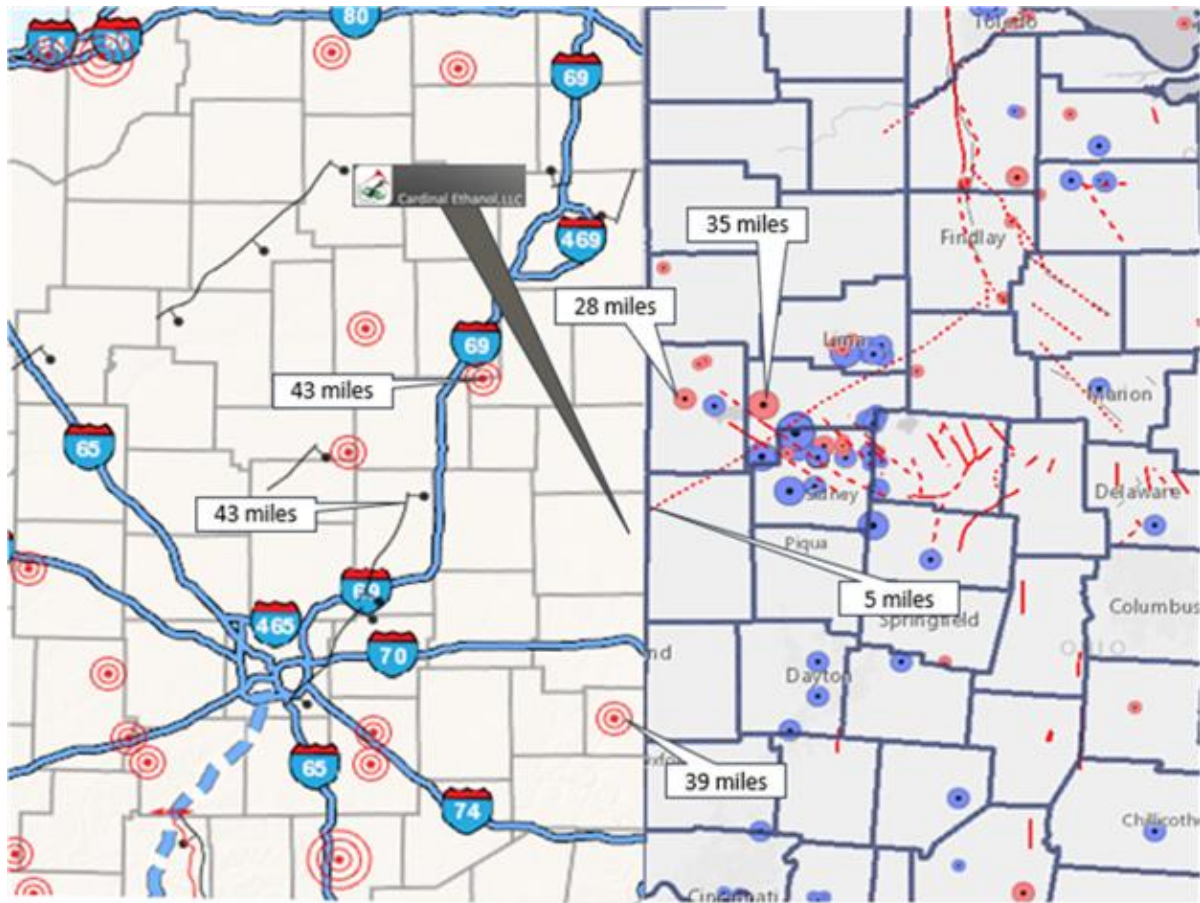


Figure 37: 2.5 or greater magnitude epicenters within 100 miles from 1800 to February 2022 (USGS, 2022)

Table 15: 2.5 or greater magnitude epicenters within 100 miles from 1800 to February 2022 (USGS, 2022).

#	Date	Latitude	Longitude	depth	Magnitude
1	6/12/2015	40.955	-84.762	5	2.6
2	12/30/2010	40.43	-85.914	5	3.8
3	9/30/2008	40.41	-84.31	5	2.8
4	8/15/2006	40.71	-84.11	5	2.5
5	5/12/2006	40.74	-84.08	5	2.8
6	9/12/2004	39.604	-85.662	2.4	3.8
7	1/30/2004	40.67	-84.65	5	2.5
8	4/4/1994	40.4	-84.4	5	2.9
9	6/4/1990	41.098	-83.638	5	2.5
10	4/17/1990	40.46	-84.852	5	3
11	7/12/1986	40.537	-84.371	10	4.5
12	6/17/1977	40.707	-84.582	5	3.2
13	3/9/1937	40.47	-84.28	3	5.4
14	3/2/1937	40.488	-84.273	2	5
15	9/20/1931	40.429	-84.27	5	4.7
16	9/30/1930	40.3	-84.3		4.2
17	9/19/1884	40.7	-84.1		4.8
18	6/18/1875	40.2	-84		4.7
19	2/8/1812	39.4	-84.1		4.4
20	1/27/1812	39.6	-85		4.2



**Figure 38: Earthquake epicenters and bedrock structural features**

## 2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The following sections provide information regarding available drinking water resources and delineation of the lowermost USDW within the AoR. The AoR and Corrective Action Plan includes a discussion of the number and locations of the groundwater wells within the AoR (Attachment 2: AoR and Corrective Action, 2022).

### 2.7.1 Regional Hydrology

The project is located in the Central Till Plain section of the New Castle Till Plains and Drainageways physiographic province (IGWS). During the Pleistocene Epoch, the region was exposed to Illinoian and Wisconsin glaciation. Post-glacial streams have deposited up to 400 ft of valley fill along stretches of the major river systems. The glacially derived cover is generally less than 50 ft to over 300 ft thick in Randolph County (Figure 39).

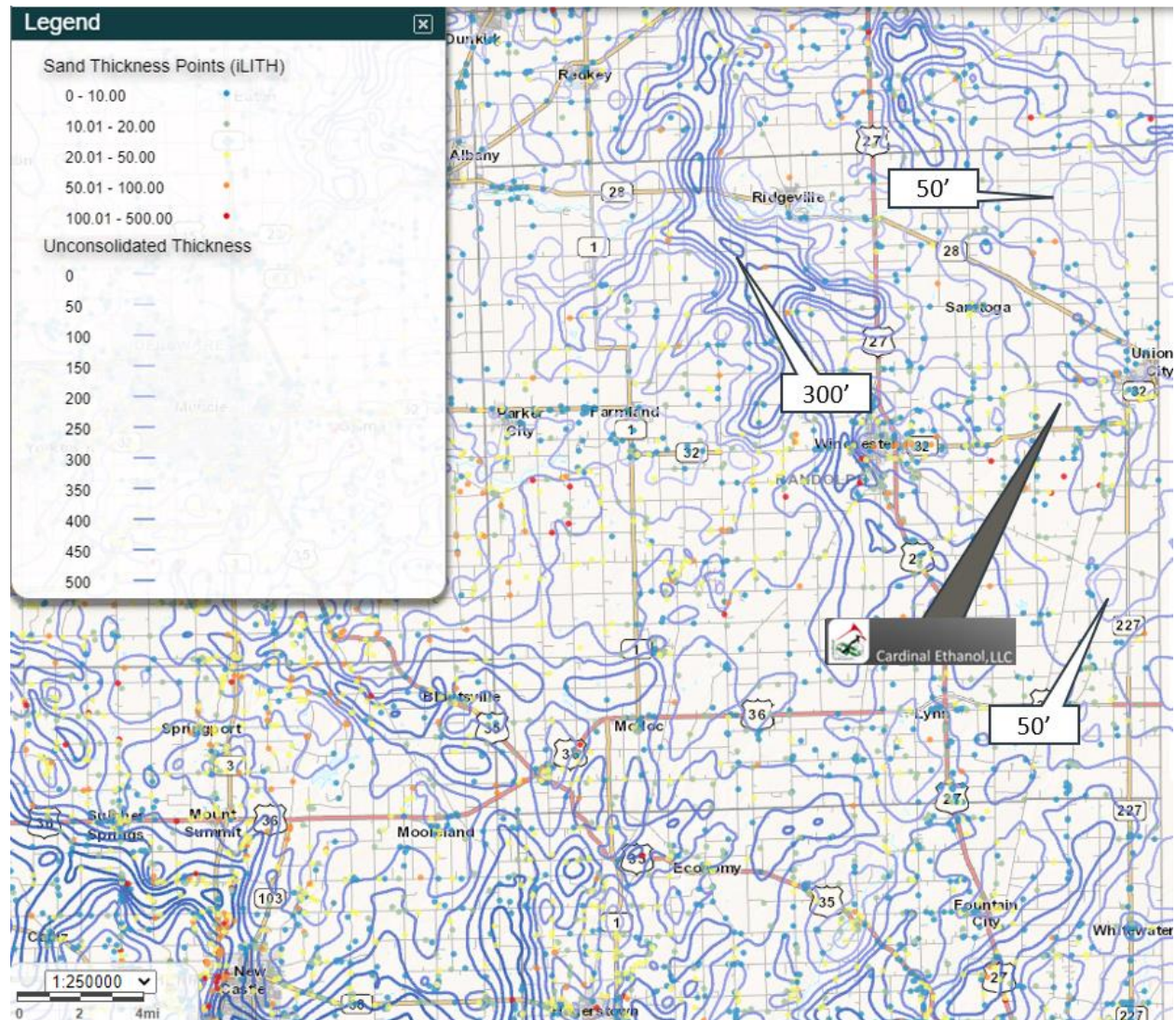


Figure 39: IGWS/ IndianaMAP unconsolidated thickness (Contour Interval (CI) = 50 ft) (State of Indiana, 2022).

## 2.7.2 Local Hydrology

In Randolph County, a relatively thin veneer of glacially derived sediments covers the bedrock surface. The project site is in the Upper Wabash River Basin and sits between the Price and Shelley Ditches, which are tributaries to the Little Mississinewa River to the northeast. Elevation of the ground level at the project site averages approximately 1,100 ft above mean sea level (MSL). Groundwater flow direction in the glacial aquifer at the project site follows the bedrock surface contours and is generally towards the north as can be seen in Figure 40.

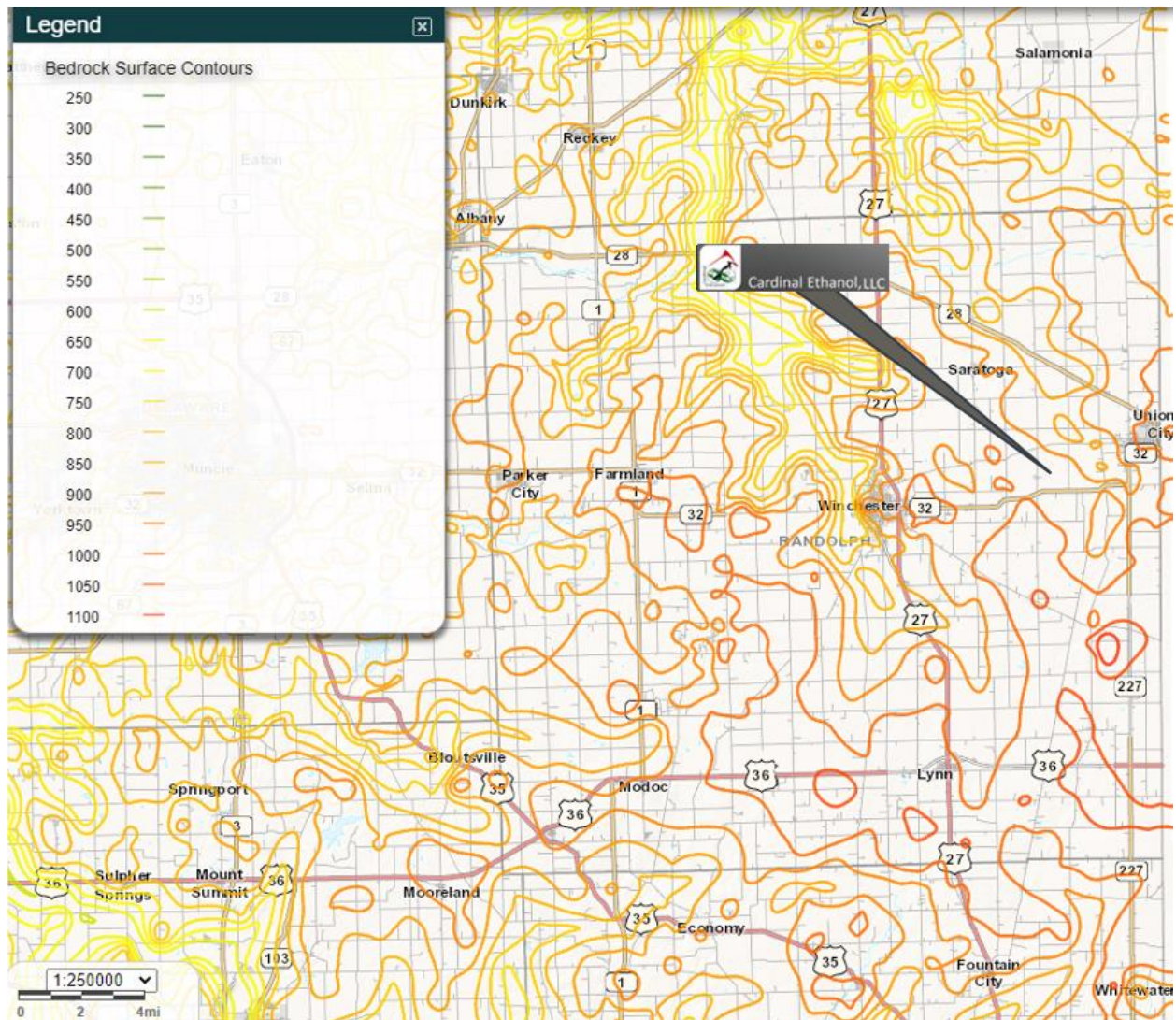


Figure 40: IGWS/ IndianaMAP bedrock surface contours (CI = 50 ft) (State of Indiana, 2022).

### 2.7.3 Near Surface Aquifers

Cardinal Ethanol completed a groundwater resource assessment in 2007 and was used for some of the content in this section (Leggette, Brashears, and Graham, Inc., 2007).

The project is in the Little Mississinewa River watershed. The main source of groundwater is the unconsolidated glacial aquifers. The project site is underlain by approximately 120 ft of glacial overburden which further overlies approximately 1,012 ft of Upper Ordovician Cincinnati Series (Figure 41). The Cincinnati Series is a succession of fossiliferous limestone and gray calcareous shale or siltstones that can be subdivided into the Kope and Maquoketa formations.

The main aquifer systems in the area are the New Castle Till and Bluffton Till Aquifer Systems (Figure 42). In Randolph County, these aquifer systems are mapped as one system because the aquifer characteristics are similar. They are composed primarily of glacial tills that are separated by intratill sand and gravel aquifers of limited thickness and extent. Unconsolidated deposits range in thickness from less than 50 to 250 ft but are typically 80 to 150 ft thick. Potential

aquifer materials include sands and gravels that are commonly 5 ft thick. In places, the New Castle Till Aquifer System and Bluffton Till Aquifer System overlie deep bedrock valleys. However, in Randolph County, there is little known unconsolidated aquifer potential in the valleys below these systems.

The New Castle Till Aquifer System and Bluffton Till Aquifer System generally have a low susceptibility to surface contamination because intratill sand and gravel units are commonly overlain by thick glacial till.

Table 16 summarizes the significant water withdrawal facilities using sand & gravel aquifers (Leggette, Brashears, and Graham, Inc., 2007). IGWS has records for the offsetting groundwater wells shown in Figure 43.

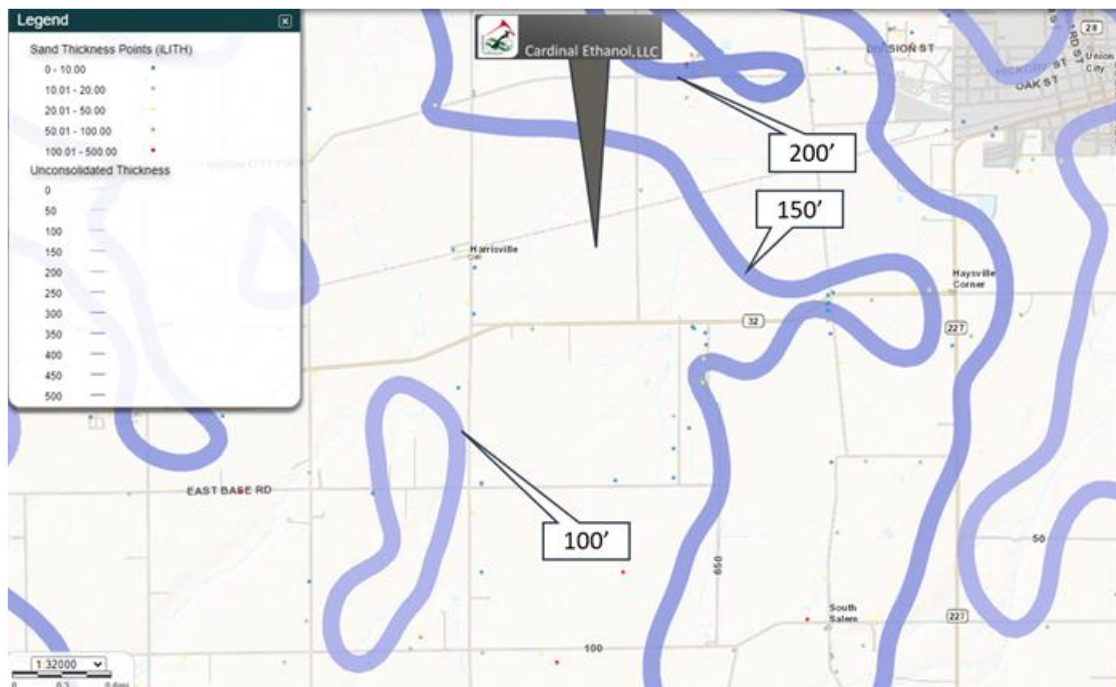


Figure 41: IGWS/ IndianaMAP unconsolidated thickness (CI = 50 ft) (State of Indiana, 2022)

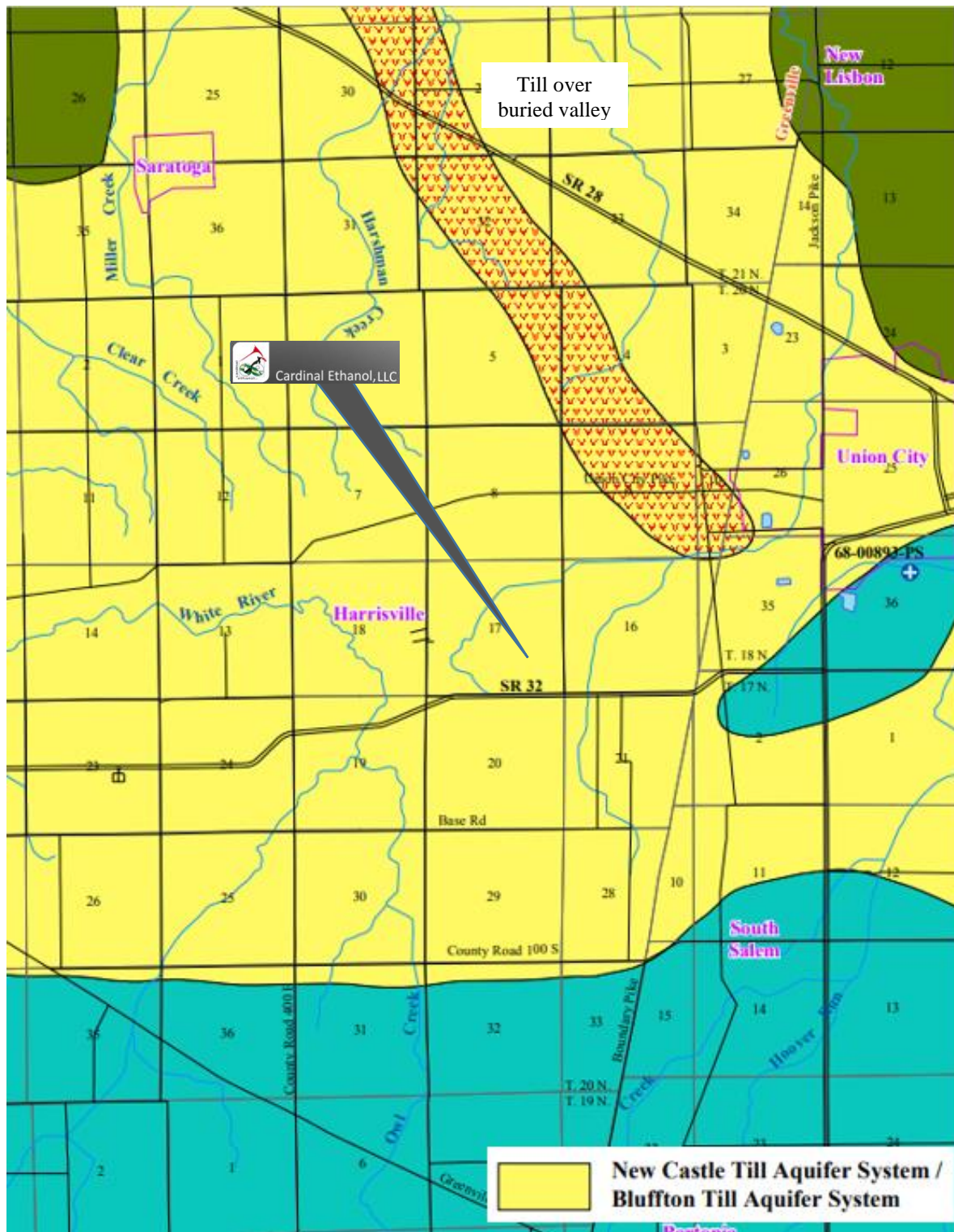


Figure 42: IDNR unconsolidated aquifer system map. The red hatching indicates till over a buried valley.  
 (Unterreiner, Unconsolidated Aquifers Systems of Randolph County, Indiana, 2006)

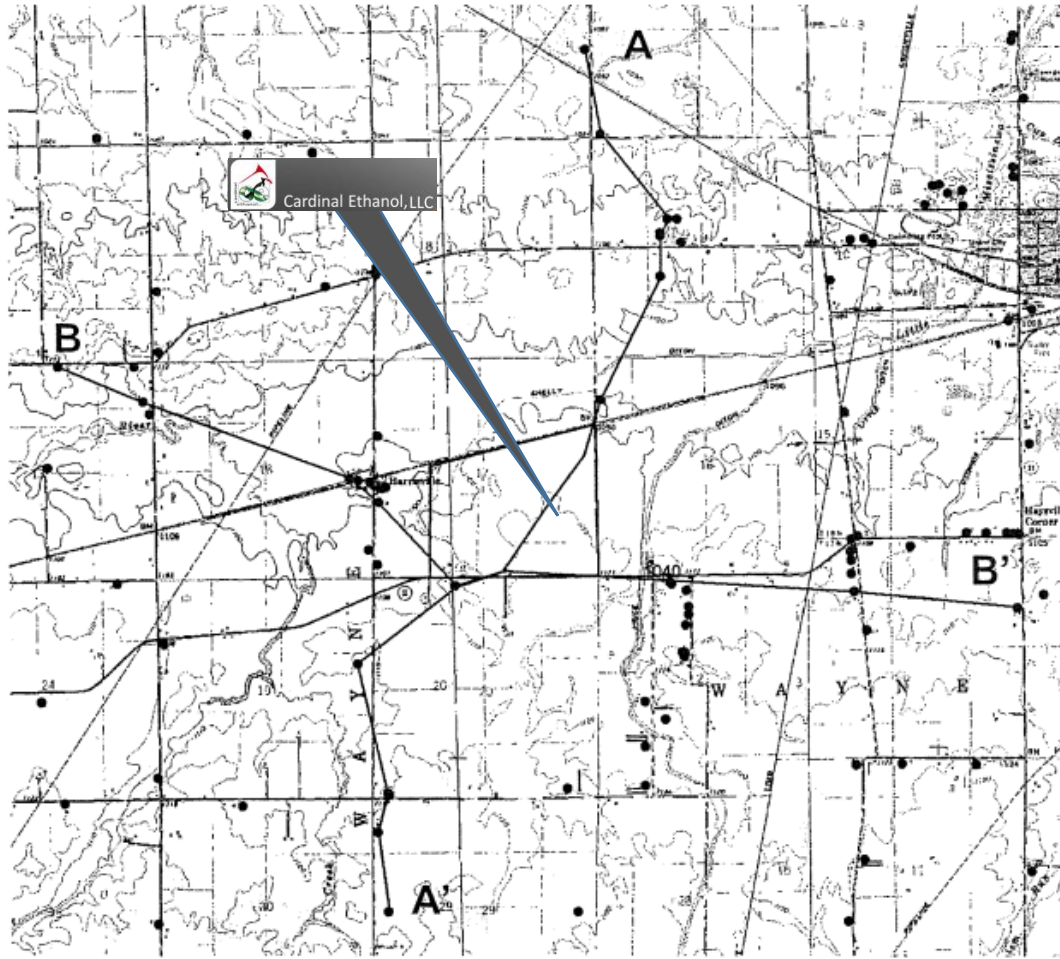
**Table 16: Significant water withdrawal facilities using sand & gravel aquifer  
(Leggette, Brashears, and Graham, Inc., 2007).**

Facility	Rated Capacity (gpm)	Well Depth (ft)	Well Diameter (in)	Average Pumping Rate During a Peak Month (gpm)
City of Union City, IN	194-420	65-116	8-14	154-207
Farmland Municipal Water Works	310	72-76	10	33-74
Indiana-American Water Co., Inc.	350-630	40-52	12-30	100-350
Klem Golf Club	80	60	8	~1
L & M Regional Water	250	128-131	8	43-48
Lynn Water Works	100-350	91-198	8-10	70
York Casket Co	11-33	60-65	12	4
Village of Union City, OH	200-250	69-80	12	51



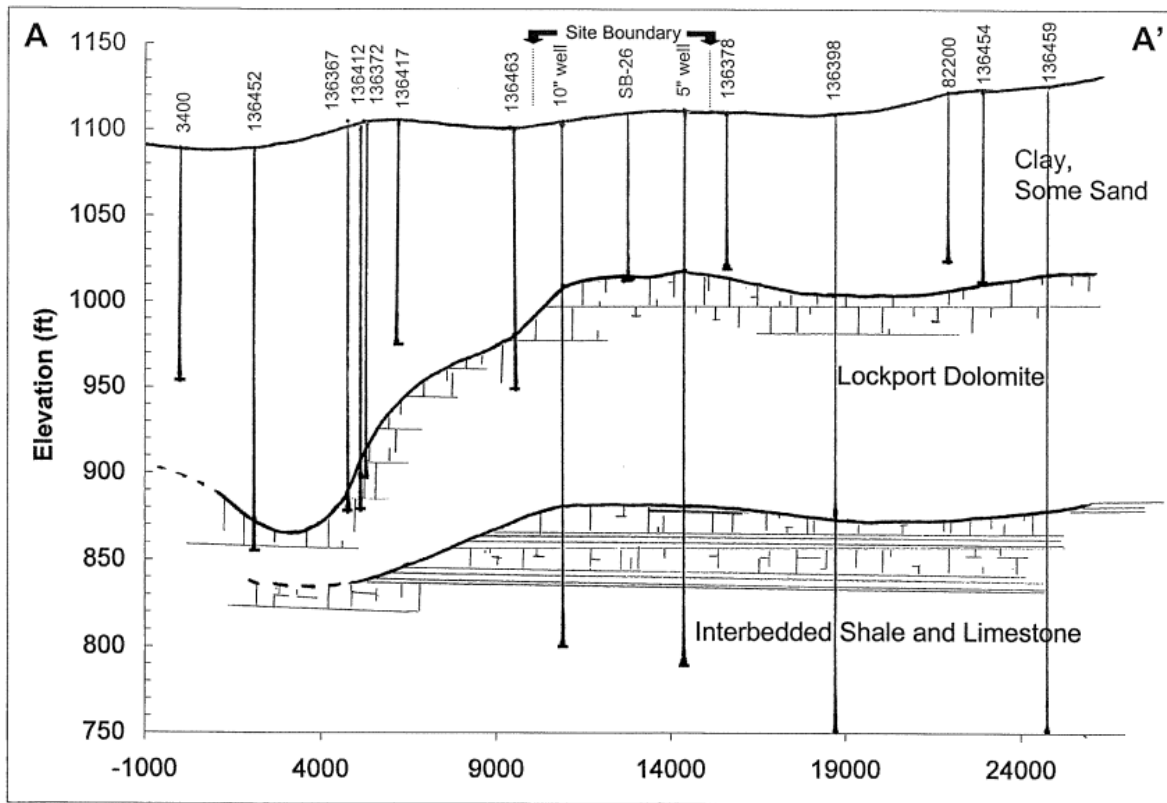
**Figure 43: Offsetting freshwater well data (State of Indiana, 2022).**  
The depths and flow rates for each well are indicated on the map.

The Cardinal Ground Water Resource Assessment 2007 also details shallow geology and hydrogeology in the area. Figure 44 shows the location of two cross sections (Figure 45, Figure 46). Figure 47 shows offsetting sand and gravel deposits.



Prepared by Leggette, Brashears and Graham, Inc.

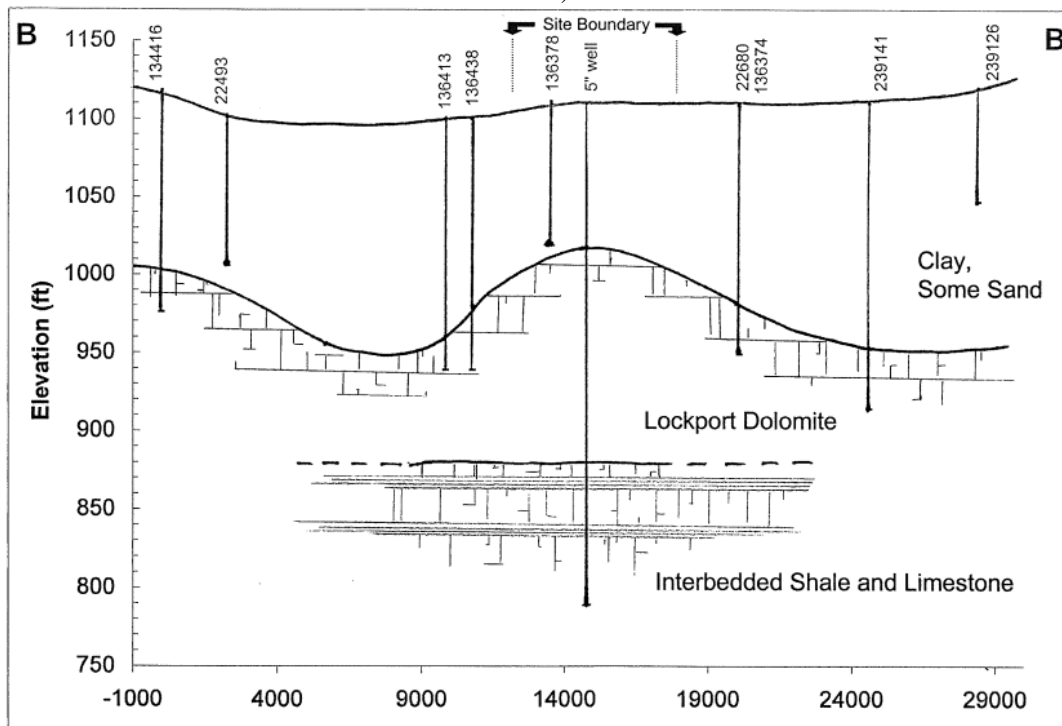
**Figure 44: Locations of the geologic cross sections presented in the preceding figures  
(Leggette, Brashears, and Graham, Inc., 2007)**



March 19<sup>th</sup>, 2007

Prepared by Leggette, Brashears and Graham, Inc.

**Figure 45: North-south geologic cross section A - A' of near surface aquifers (Leggette, Brashears, and Graham, Inc., 2007)**



March 19<sup>th</sup>, 2007

Prepared by Leggette, Brashears and Graham, Inc.

**Figure 46: East-west cross section B - B' of near surface aquifers (Leggette, Brashears, and Graham, Inc., 2007)**

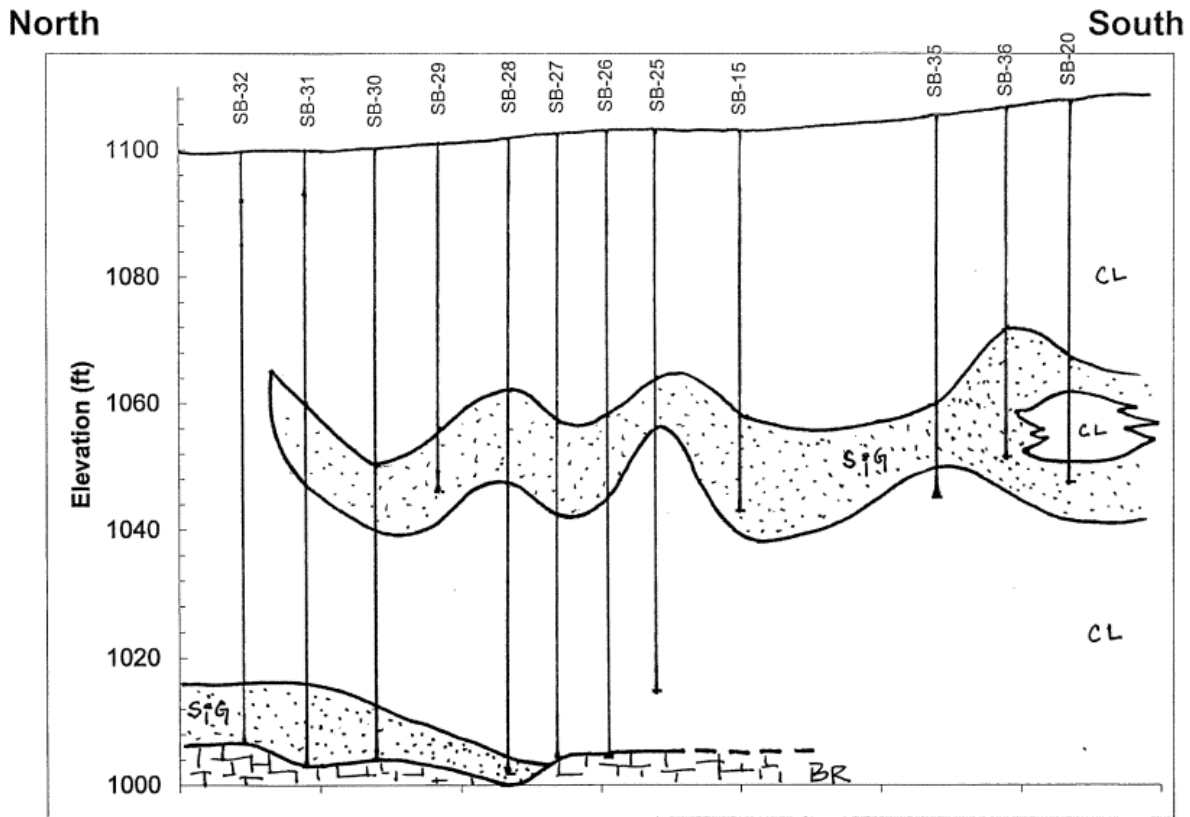


Figure 47: Offsetting sand and gravel deposits cross section frp, the Terracon borings in the area around the project (Leggette, Brashears, and Graham, Inc., 2007)

#### 2.7.4 Determination of Lowermost USDW

A USDW is defined by the EPA as an aquifer that (40 CFR 146.3):

- Supplies any public water system
- Contains a sufficient quantity of [groundwater](#) to supply a public water [system](#); and
  - Currently supplies drinking water for human consumption, or
  - Contains fewer than 10,000 mg/l total dissolved solids (TDS),
- Which is not an exempted aquifer.

For the purposes of this project, the lowest USDW depth is identified by Permit Number 30922 (IGS Well ID/PDMS 144860) located 1.5 miles SW of Cardinal CCS1 (Attachment 2: AoR and Corrective Action, 2022). The Well Plugging Plan for this well identifies the lowest USDW at 450 ft as shown in Figure 48. Figure 49 shows the appended geophysical log indicating Maquoketa Shale top at 240 ft and lowest USDW (450 ft).

Plan revision number: N/A  
Plan revision date: July 4, 2022


WELL PLUGGING PLAN		FOR STATE USE ONLY									
State Form 54872 (R4 / 3-20) Form No. P2		Date Received (month, day, year) <b>8-31-2021</b>	Initials <b>EBY</b>								
INDIANA DEPARTMENT OF NATURAL RESOURCES Division of Oil and Gas 402 West Washington Street, Room W293 Indianapolis, IN 46204 Telephone: (317) 232-4055 Internet: <a href="http://www.in.gov/dnr/dnroll">http://www.in.gov/dnr/dnroll</a>		Date Approved (month, day, year) <b>9-1-2021</b>	Initials								
		Date Denied (month, day, year)	Initials								
		Date Modified (month, day, year)	Initials								
		PART I GENERAL INFORMATION									
Operator: Orphan Site		Telephone Number: 317-417-6556	E-mail: <a href="mailto:broyer@dnr.in.gov">broyer@dnr.in.gov</a>								
Lease-Well Number: Fred Tibbetis #1		Well Type: Oil & Gas	Permit Number: 30922								
County: Randolph	Scheduled plugging date: (month, day, year) Winter 2021-22	Section 19	Township 20N Range 15E 1/4's NE, NE, SE								
Surface:		GL: 1109	KB:								
<table border="1"><thead><tr><th>Size</th><th>Length</th><th>Hole</th><th>Cement</th></tr></thead><tbody><tr><td>9 5/8</td><td>124</td><td></td><td>60 sx</td></tr></tbody></table>		Size	Length	Hole	Cement	9 5/8	124		60 sx		
Size	Length	Hole	Cement								
9 5/8	124		60 sx								
Long String:											
<table border="1"><thead><tr><th>Size</th><th>Length</th><th>Hole</th><th>Cement</th></tr></thead><tbody><tr><td>4.5</td><td>1245</td><td>7 7/8</td><td>75 sx</td></tr></tbody></table>		Size	Length	Hole	Cement	4.5	1245	7 7/8	75 sx		
Size	Length	Hole	Cement								
4.5	1245	7 7/8	75 sx								
Liner / Intermediate Casing:											
<table border="1"><thead><tr><th>Size</th><th>Length</th><th>Hole</th><th>Cement</th></tr></thead><tbody><tr><td></td><td></td><td></td><td></td></tr></tbody></table>		Size	Length	Hole	Cement					USDW Depth: 450'	
Size	Length	Hole	Cement								
Estimate top of cement (TOC): 895'		Well flowing? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No									
Well Orientation: Vertical: <input checked="" type="checkbox"/> Yes Horizontal: <input type="checkbox"/> Yes		Will you be disposing of NORM related waste during this plugging? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No If yes, see Part III below.									
Existing Perforations:		Is well located in a commercially minable coal resource area? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No If so, was the entity with rights to the coal rights notified? <input type="checkbox"/> Yes When? Who was notified?									
		Comments: <u>If flow does not stop then CIBP will have to be set at 1115' with 1 sack bailed on top.</u>									

Figure 48: Permit Number 30922 (IGS Well ID/PDMS 144860) well plugging plan. USDW is identified at 450 ft by IDNR.

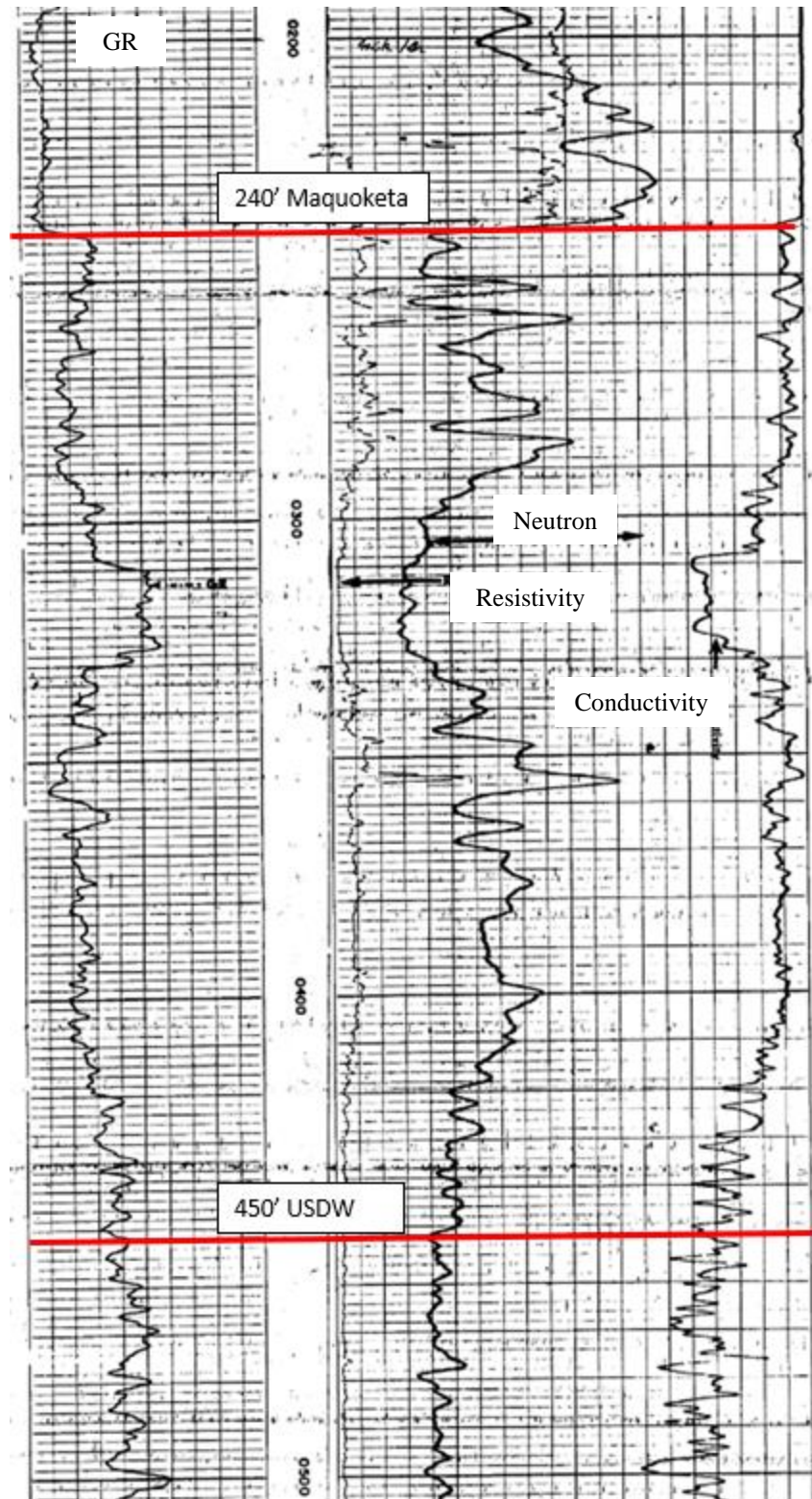


Figure 49: Permit Number 30922 (IGS Well ID/ PDMS 144860). IDNR has identified the lowermost USDW at 450 ft

#### 2.7.4.1 *Silurian and Devonian Carbonates*

In Randolph County, the younger Devonian aged carbonates are not present, and this aquifer system consists only of Silurian age carbonates. The Silurian and Devonian Carbonates Aquifer System outcrops/subcrops throughout much of Randolph County. The total thickness of this system in the county ranges from 0 to about 200 ft.

Wells penetrating the Silurian and Devonian Carbonates Aquifer System have reported depths ranging from 35 to 380 ft but are commonly 100 to 180 ft deep. The rock column penetrated in this system typically ranges from 20 to 70 ft; although many of the deeper wells also reach the upper portion of the underlying Maquoketa Group.

Wells using the Silurian and Devonian Carbonates Aquifer System are generally capable of meeting the needs of domestic users and some high-capacity users in this county. Domestic well yields commonly range from 10 to 35 gallons per minute (GPM). Static water levels typically range from 15 to 35 ft below the land surface. A few flowing wells have been reported for this bedrock aquifer system in the county. High-capacity well depths range from approximately 40 to 400 ft below the land surface. Several of the high-capacity wells have contributions from both the Silurian and Devonian Carbonates Aquifer System and the underlying Maquoketa Group Aquifer System (Table 17).

This aquifer system is generally not very susceptible to surface contamination due to the thick clay deposits over most of the county. However, solution features (caves) are described in a few well records suggesting minor karst development. However, there are localized areas, especially near the White and the Mississinewa Rivers, where the bedrock surface is shallow or exposed. Therefore, these areas are at moderate to high risk for contamination (Unterreiner, Bedrock Aquifer Systems of Randolph County, Indiana, 2006).

Facility	Rated Capacity (gpm)	Well Depth (ft)	Well Diameter (in)	Average Pumping Rate During a Peak Month (gpm)
Town of Parker City	120-190	300-400	6-10	95-100
Ridgeville Water Department	150	124-140	6-8	55
Meshberger Bros Stone Corporation	60-80	160-180	6	1-25
Randolph Central School Corporation	100	42	8	1.5
City of Union City, IN*	200-310	270-300	10	165-215
Farmland Municipal Water Works*	85	125	8	35-75
Cassel Farms, Inc	600	300	8	12
York Casket Co*	33	160	6	4
Village of Union City, OH*	50-75	142-188	5.5-10.75	20-40

\* Facilities which also operate wells in the unconsolidated glacial material and therefore do not meet all demand from bedrock wells

Table 17: Significant water withdrawal facilities using limestone aquifer (Leggette, Brashears, and Graham, Inc., 2007)

#### 2.7.4.2 Ordovician Maquoketa Group

The outcrop/subcrop area of this aquifer system is limited to the three main bedrock valleys in this county. The Maquoketa Group consists mostly of shales with interbedded limestone units. Although the Maquoketa Group Aquifer system is approximately 800 to 900 ft thick in the county, typically little more than the top 100 ft is used for water production.

In Randolph County, some wells completed in the Maquoketa Group Aquifer System are open to and receive some water from the Silurian and Devonian Carbonates Aquifer System. However, wells completed solely in the Maquoketa Group Aquifer System are generally capable of meeting the needs of domestic users in this county. Wells exclusively using the Maquoketa Group Aquifer System in Randolph County have reported depths ranging from 79 to 423 ft but are commonly 120 to 300 ft deep. The rock column penetrated in this system typically ranges from 20 to 80 ft. Yields for domestic wells generally range from 10 to 30 GPM and static water levels are commonly 10 to 25 ft below the land surface.

The Maquoketa Group Aquifer System is generally not very susceptible to contamination from the land surface because thick layers of clay-rich material overlie the bedrock (Unterreiner, 2006).

The Maquoketa Group is present at the bedrock surface in small areas in Randolph, Delaware, Henry, and Madison counties. It is the least extensive bedrock aquifer system in the West Fork White River basin. The rocks in this group are the oldest at the bedrock surface in the basin, exposed only in pre-glacial valleys that have since been filled with glacial drift.

The thickness of the Maquoketa Group is highly variable because the top of the group is an erosional disconformity and has local relief of more than 100 ft due to pre-glacial erosion of the bedrock surface.

Wells completed in the Ordovician bedrock aquifer system in the West Fork White River Basin range from 112 to 600 ft deep. Well depth depends upon bedrock elevation and unconsolidated material thickness. The bedrock surface elevation for a specific area can be estimated using Figure 40. The thickness of unconsolidated material for an area can be estimated using Figure 39. The penetration of wells into bedrock in this aquifer system is also highly variable and ranges from about 10 to more than 290 ft. Data are not sufficient to correlate yields with the depth of penetration. Static water levels in wells developed in this system range from 0 to 60 ft beneath the land surface but are usually between 10 and 50 ft below ground.

In general, because of the high shale content, the Maquoketa Group is considered to be an aquitard having poor yield potential. However, in the West Fork White River Basin higher yields are reported than in other parts of the state because there is higher limestone content in the upper part of the group. The moderate yield potential in the basin is related to joints and solution cavities that formed in the limestone units.

Well yields from the Maquoketa Group, as indicated by drillers' tests, range from 0 to 200 GPM. Yields of 5 to 15 GPM are typical and yields above 15 GPM are not common. Dry holes have also been reported to IDNR (Unterreiner, Bedrock Aquifer Systems of Randolph Country, Indiana, 2006).

Generally, the Maquoketa Group is not highly productive, and it is typically used only when the overlying drift does not contain an adequate sand and gravel aquifer. It is bounded by the younger, overlying Silurian and Devonian Carbonate Aquifer System.

### 2.7.5 Topographic Description

The Hoosier #1 Project is located in Section 17, Wayne Township, Randolph County, Indiana near Union City at an elevation of approximately 1,100 ft. This is an area of minimal flood hazard as established by the FEMA (Figure 50). The Quaternary surface geology is the result of Wisconsin (Huron-Erie Lobe) glaciation and filled with loam till (Figure 51). At the project site, glacial deposits are approximately 120 ft thick.

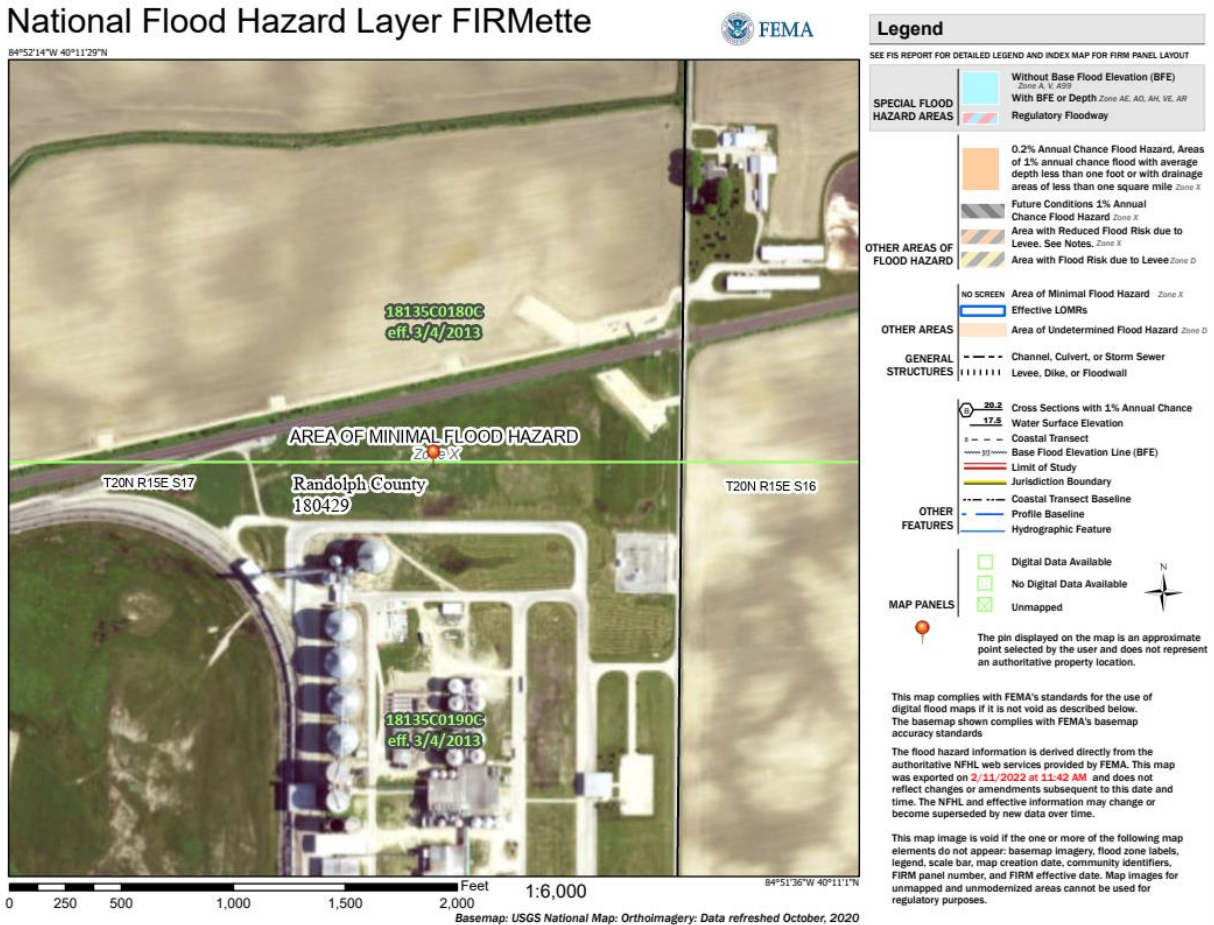


Figure 50: National Flood Hazard Layer FIRMette (FEMA, 2022)

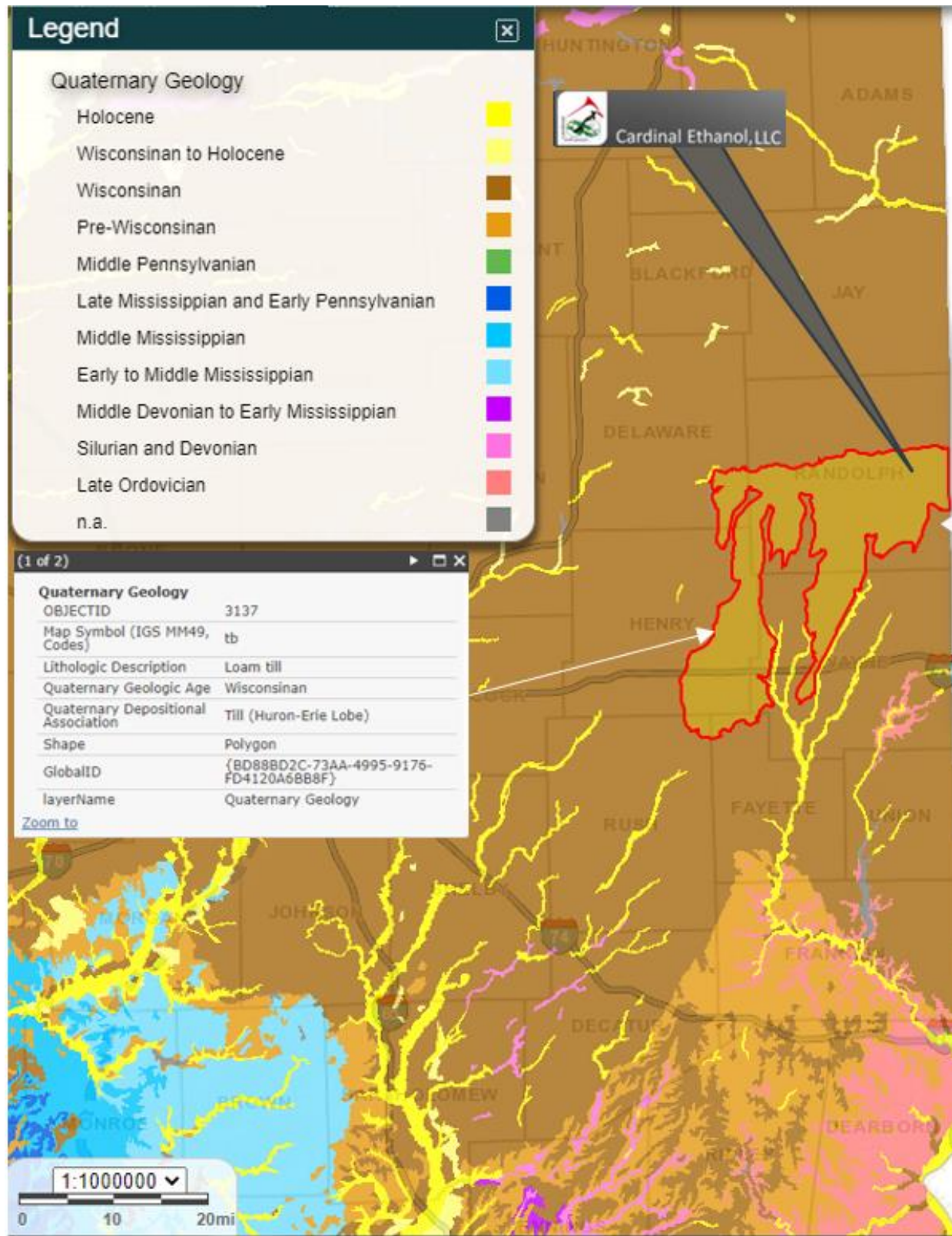


Figure 51: Quaternary geology related to the Wisconsinan (Huron-Erie Lobe) Glaciation (State of Indiana, 2022).

## **2.8 Geochemistry [40 CFR 146.82(a)(6)]**

There are a limited number of wells that penetrate the Mt. Simon Sandstone and, currently, little data to support detailed aqueous or solid phase geochemical modeling for the project. The Mt. Simon Sandstone does contain feldspar, potentially carbon cement, and clay minerals. These minerals are reactive with CO<sub>2</sub>, and it is expected that changes to the aqueous geochemistry of the Mt. Simon Sandstone fluids will occur once CO<sub>2</sub> injection commences.

The computational modeling investigated the effect of mineralization on long-term trapping of CO<sub>2</sub> based on the potential reactions with calcite, anorthite, and kaolinite as part of the PISC Alternative Timeframe using the information currently available (Attachment 9: Post-Injection Site Care, 2022). This modeling demonstrated that mineralization is not expected to play a significant role in trapping for thousands of years. No other geochemical or reactive transport modeling has been completed for the injection zone or the confining zone at this time given the scarcity of data.

The Pre-Operational Testing Program details the data that will be acquired in CCS1 and from the Deep Observation Well (OBS1) that may be used to support future geochemical modeling (Attachment 5: Pre-Op Testing Program, 2022). The mineralogy of the injection zone and confining zone will be determined through a combination of core analysis and well logging. Well log data will also be acquired through the lowermost USDW and ACZ monitoring zone to assist in establishing the mineralogy of these formations.

Fluid samples will be acquired from the lowermost USDW, the ACZ monitoring interval, and the injection zone when the project wells are drilled. The Testing and Monitoring Plan details the parameters and analytes that will be used to establish baseline conditions for these formations as well as during the injection phase of the project (Attachment 7: Testing And Monitoring, 2022). The aqueous geochemistry data gathered during the pre-operational phase of the project will also be used to support future geochemical modeling work. Geochemical modeling will likely focus on reactions in the injection zone and any reactions in the confining zone that may impact long-term containment and endangerment of USDWs.

## **2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)**

The Pre-Operational Testing Program presents the data that will be collected in order to determine and verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the injection zone, confining zone, and other relevant geologic formations via petrophysical logging and analysis, and core acquisition and testing (Attachment 5: Pre-Op Testing Program, 2022). In addition, baseline 3D surface seismic data will be acquired during the pre-injection phase of the project to assist in characterizing injection zone and confining zone rock properties away from CCS1 and OBS1.

At this time, the project does not plan to acquire baseline atmospheric or soil gas data nor are there plans to pursue atmospheric or soil gas monitoring during the injection phase of the project.

## **2.10 Site Suitability [40 CFR 146.83]**

The AK Steel and INEOS (BP Lima) disposal wells provided useful data on the Eau Claire Formation and Mt. Simon Sandstone and were used as analogs for this project. In addition, study of other regional well data and computational modeling indicate that the geologic setting of the proposed injection zone has the capacity to store 13.5 million metric tons of CO<sub>2</sub> over 30 years of injection based on:

- Depth to the top of the injection zone: 3,159 ft
- Thickness of the injection zone: 459 ft
- Lateral continuity of the Mt. Simon Sandstone over the region
- Estimated porosity of the injection zone: average of 10.9%
- Permeability of the injection zone: average 31 mD

Given the lateral continuity, open nature of the injection zone, and computational modeling, the injection zone is expected to have more than adequate capacity for the injection volumes proposed. CO<sub>2</sub> plume development is expected to be controlled by heterogeneities within the injection zone. These heterogeneities will be characterized using a combination of well log, core, and 3D surface seismic data acquired during the pre-operational phase of the project (Attachment 5: Pre-Op Testing Program, 2022). The AoR and Corrective Action Plan includes discussion of the capacity estimates for the injection zone (Attachment 2: AoR and Corrective Action, 2022).

The Eau Claire Shale is expected to be an excellent confining zone for the project. It is estimated to be 487 ft thick at the project site and has excellent lateral continuity across the basin. Based on the petrophysical analysis of sixteen wells in the region, it has very low permeabilities that average 2.7 mD. Computational modeling indicates that the Eau Claire Shale will be an effective barrier to upward migration of CO<sub>2</sub> and injection zone fluids (Attachment 2: AoR and Corrective Action, 2022). Data gathered during the pre-operational phase of the project is expected to verify that the Eau Claire Shale is a suitable confining zone (Attachment 5: Pre-Op Testing Program, 2022).

While the Eau Claire Shale is expected to be a highly competent confining zone, additional formations within the Knox Group afford additional containment including the Knox Dolomite, which has permeabilities from 0.00005 – 24.1 mD at the INEOS (BP Lima) Nitriles disposal site. If injection zone fluids were to migrate past the primary confining zone, multiple formations within the Knox Group will prevent the fluids from migrating up to the lowermost USDW. Other similar projects indicate the Middle Run and Precambrian basement rock will act as an impermeable lower confining zone for the Mt. Simon Sandstone injection zone.

No deep wells penetrate the confining zone within the AoR. The closest well (IGWS #144601) penetrating the Eau Claire Formation is 13 miles to the southwest, which is a significant distance outside of the AoR. No natural conduits, such as fault or fractures, for injection zone fluid migration beyond the confining zone have been identified on the existing 2D surface seismic data. It is anticipated there will be a lack of large-aperture tension fractures in Cardinal CCS1, as determined from the image and sonic logs, indicating that the well is not proximal to normal (tensional) faults that might be close to failure.

The well casing, tubing, and cement used through the confining zone and injection zone will be CO<sub>2</sub> resistant (Attachment 4: Well Construction, 2022). It is expected that the CO<sub>2</sub> will interact with mineral components of the Mt. Simon Sandstone over time. As discussed in Section 2.9, once the project acquires more site-specific data during the pre-injection phase of the project, it will be used to model the potential geochemical reactions that will occur in the injection zone. These reactions will be monitored using fluid samples that will be taken from the injection zone in OBS1 during the first three years of the injection phase of the project (Attachment 7: Testing And Monitoring, 2022). Geochemical interactions between the CO<sub>2</sub> and the confining zone are

not expected to impact long-term containment of the CO<sub>2</sub> based on the thickness and lack of fractures the project expects to encounter in the confining zone.

### 3 AoR and Corrective Action

Through the computational modeling, a 2.26-mile AoR has been determined for this project (Attachment 2: AoR and Corrective Action, 2022). After a thorough review of all identified wells in the region, it has been determined that there are no wells within the AoR that penetrate the confining zone, and there is no requirement for corrective action.

#### AoR and Corrective Action GSDT Submissions

**GSDT Module:** AoR and Corrective Action

**Tab(s):** All applicable tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

- ☒ Tabulation of all wells within AoR that penetrate confining zone [40 CFR 146.82(a)(4)]
- ☒ AoR and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b)]
- ☒ Computational modeling details [40 CFR 146.84(c)]

### 4 Financial Responsibility

The financial assurance estimation for the project was divided into four “buckets.” Those being: Corrective Action, Injection Well Plugging and Abandonment, Post Injection Site Care and Closure, and the Emergency and Remedial Response Plan (ERRP). The first three buckets will be covered by a surety bond, and the last will be covered by an insurance policy. These items will be set up using a yet-to-be-determined financial institution. Prior to commencement of injection operations the financial institution of choice will be selected and proper information and updates to the permit application will be provided.

Internal estimates and external vendor quotes were used to assemble the estimates for the first three buckets. All appropriate quotes that were provided from vendors are provided with the submittal documentation. The cost estimate for the ERRP was developed in tandem with Industrial Economics (IEc). Their full report is provided with the submittal documentation.

Further detail is provided in the Financial Assurance section of this permit application (Attachment 3: Financial Responsibility, 2022).

#### Financial Responsibility GSDT Submissions

**GSDT Module:** Financial Responsibility Demonstration

**Tab(s):** Cost Estimate tab and all applicable financial instrument tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ Demonstration of financial responsibility [40 CFR 146.82(a)(14) and 146.85]

## 5 Injection Well Construction

Vault intends to use materials of construction (casing, cement, etc.) that are verified by independent third-party sources as suitable for the worst-case corrosive load expected to occur during the life of the project. Verification of the suitability is provided as part of the supporting documents for (Attachment 4: Well Construction, 2022).

The new well is planned to have two (2) hole sections: Surface, from surface to approximately 530 ft (below the base of the USDW); and long string, from approximately 530 to approximately 3,689 ft (if going to basement) or approximately 3,708 ft (if not going to basement).

Should a substantial lost circulation zone (LCZ) be encountered during the drilling of the long string section, well control and loss prevention measures will be implemented, and the hole will be reamed up to run a contingent intermediate string. The potential anticipated LCZ is the Potosi. The end of this section is to be determined (TBD) and is dependent on drilling conditions experienced in the field. It is, however, anticipated that this section total depth (TD) will occur above the top of the Eau Claire Formation.

Wellheads will be used with appropriately sized components and materials of construction based on the build of the wellbore. The wellhead will vary depending on whether the intermediate contingency section is needed or not.

Following installation of the long string casing and cement, perforations will be made into the casing to access the Mt. Simon Sandstone for injection.

Schematics for the wellbore and wellhead (planned and contingency) are provided in the well construction plan attachment of the permit application.

Further details on the proposed stimulation program, construction plan, and materials of construction are provided in this section as well as in the well construction attachment.

### 5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

It is not currently anticipated that any additional stimulation will need to be performed on the well after initial completion, other than to clean out the perforations made in the long-string casing.

Vault reserves the right to perform intermediate stimulation on this well, should the need arise. A list of some of the common remediation techniques that may be deployed in the future is listed below. Note that this is not an exhaustive list and additional technologies or treatments may be used. Further detail on methods, materials, and chemicals to be used during treatments is provided in (Attachment 4: Well Construction, 2022).

- Matrix acid stimulation,
- Coil tubing chemical stimulation,
- Coil tubing mechanical stimulation,
- Perforations.

Stimulations will occur as necessitated by well conditions. These will be identified by evaluating well performance over time. The necessary notification will be provided to the Agency prior to any field mobilization. Within this notification, detail on the proposed procedure, equipment, and chemicals to be used will be provided.

## **5.2 Construction Procedures [40 CFR 146.82(a)(12)]**

The injection well will be drilled as a new well. Multiple strings of carbon steel and 13-Chrome casing will be installed and cemented in place to protect the USDWs and other strata overlying the injection formation. Fluids will be injected into the Mt. Simon Sandstone using internally coated carbon steel casing landed in in a nickel coated packer. The Mt. Simon Sandstone will be accessed through perforations in the long string casing.

A high-level procedure is provided below. A more detailed schedule and procedure is provided in Attachment 4.

1. Conductor casing will be drilled then cemented in place.
2. Surface hole will be drilled. This hole will be drilled to a sufficient depth below the base of the USDW such that the entire USDW can be logged during open and cased hole logs.
3. Open hole logs will be run.
4. Casing will then be run and cemented in place.
5. After allowing sufficient time for the cement to harden, cased hole logs will be run, and the casing will be pressure tested.
6. Long string hole will be drilled. This hole will be drilled into basement (if OBS1 does not penetrate it) or above basement (if OBS1 does penetrate it).
  - a. Should a substantial LCZ occur during drilling the long string section, an intermediate contingent string of casing will be run.
  - b. Prior to operations, well control and loss prevention measures will be implemented until the well is stable.
  - c. The hole will be reamed up to size and open hole logs will be run.
  - d. Casing will then be run and cemented in place.
  - e. After allowing sufficient time for the cement to harden, cased hole logs will be run, and the casing will be pressure tested.
7. Open hole logs will be run.
8. Casing will then be run and cemented in place.
9. After allowing sufficient time for the cement to harden, cased hole logs will be run, and the casing will be pressure tested.
10. Perforations will be made in the long string casing into the Mt. Simon Sandstone.
11. The tubing, packer, and wellhead will then be installed.

Specifications on the tools, equipment, casing, cement, and other things are provided in more detail in Attachment 4. All materials of construction are designed to API standards.

### **5.2.1 Casing and Cementing**

Table 18 and Table 19 display the safety factors and safety factor loads based on the proposed well design. It is noted that an 80% derating factor is applied prior to any analyses. This implies an additional 1.20 safety factor on top of those displayed in the table. Additionally, material and specification derating based on tensile loading is also considered. Finally, worst-case analyses (i.e., evacuated casing while pumping cement while also pulling up at the max tensile rating)

were considered in casing evaluation. Anticipated loads are displayed first, followed by worst case loads.

In addition to these analyses, cyclic and temperature loading analysis was performed. The results of this analysis are presented in (Attachment 4: Well Construction, 2022).

Table 20 displays the setting depths and specifications of the casing to be used for the well. All casing conforms with API specifications. Table 22 shows the design parameters of the casing, tubing, and packer to be used for the well.

Details on the cement program are provided in (Attachment 4: Well Construction, 2022). All cement used conforms with API standards. Corrosion resistant cement will be used from the bottom of the well to above the top of the Eau Claire Formation.

Mechanical integrity will be demonstrated as part of the initial completion, and routinely as discussed in (Attachment 5: Pre-Op Testing Program, 2022) and (Attachment 7: Testing And Monitoring, 2022), respectively.

All materials of construction are suitable for the anticipated loading and are not anticipated to decrease in suitability over time.

**Table 18. Casing Safety Factors for Design.**

<b>Burst</b>	<b>Collapse</b>	<b>Tensile</b>	<b>Von Mises</b>
1.2	1.2	1.5	1.5

**Table 19. Casing Safety Factor Loads for Design.**

<b>String</b>	<b>Burst</b>	<b>Collapse</b>	<b>Tensile*</b>	<b>Von Mises*</b>
Surface	1.54	52.36	18.87	6.68
Intermediate (Contingency)	2.38	2.19	4.20	3.14
Long String	2.22	3.77	5.34	3.22
Injection Tubing	2.59	6.92	5.63	1.63

\*100,000 pounds (lbs) overpull

**Table 20. Casing and Tubing details.**

<b>Casing String</b>	<b>Casing Depth</b>	<b>Borehole Diameter</b>	<b>Wall Thickness</b>	<b>External Diameter</b>	<b>Casing Material</b>	<b>String Weight</b>
Surface	560 ft	17-1/2 inches	0.38 inches	13-3/8 inches	54.5 lbs./ft, J55, STC	30,520 lbs
Long String (Metal)	2,600 ft	8-1/2 inches	0.362 inches	7 inches	26 lbs./ft, L80, LTC	67,600 lbs
Long String (Chrome)	2,600-3,693 ft	8-1/2 inches	0.362 inches	7 inches	26 lbs./ft, 13CR80, Special	28,418 lbs
Injection Tubing	0-3,184 ft	6.276 Inches*	0.254 inches	3.5 inches	9.3 lb/ft, L80, Special, internally coated	29,611 lbs

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Intermediate (contingency)	0-2,600 ft	12-1/4 inches	0.352 inches	9-5/8 inches	36 lbs./ft, J55, STC	93,600 lbs

\*Internal diameter of long string casing

**Table 21. Casing, Tubing, and Packer Details**

Material	Setting Depth (ft)	Tensile Strength	80% of Tensile Strength	Burst Strength	80% of Burst Strength	Collapse Strength	80% of Collapse Strength	Material of Construction
Surface Casing	560	514,000 lbs	411,200 lbs	2,730 psi	2,184 psi	1,130 psi	904 psi	54.5 lbs./ft, J55, STC
Long Strong Casing	2,600	511,000 lbs	408,800 lbs	7,240 psi	5,792 psi	5,410 psi	4,328 psi	26 lbs./ft, L80/13Cr80, LTC
Injection Tubing	3,184	207,200 lbs	165,760 lbs	10,160 psi	8,128 psi	10,540 psi	8,432 psi	9.3 lbs./ft, L80 lined, Special
Intermediate (contingency)	2,600	394,000 lbs.	315,200 lbs.	3,520 psi	2,816 psi	2,020 psi	1,616 psi	36 lbs./ft, J55, STC
Baker Signature F	3,184							Chrome/ Nickel plated

### 5.2.2 Tubing and Packer

The tubing, internally coated 3.5-inch L80 pipe, is anticipated to withstand the corrosive loading experienced during normal operations. The internal coating to be used has been routinely used in waste disposal and Enhanced Oil Recovery (EOR) projects. This internal coating has proved to be suitable for use in more corrosive environments than are anticipated to be experienced in this application. Further detail on the suitability is provided in (Attachment 4: Well Construction, 2022).

The packer to be used for the project is Baker Signature F style retrievable packer. This packer will also be nickel coated to prevent any corrosion. This packer and coated mechanism are typical for disposal purposes and designed to prevent corrosion or leakage. Further details on the packer are provided in (Attachment 4: Well Construction, 2022).

## 6 Pre-Operational Logging and Testing

Details on the pre-operation testing plan are provided in the relevant section of this permit application (Attachment 5: Pre-Op Testing Program, 2022).

Pre-Operational Logging and Testing GSDT Submissions
<b>GSDT Module:</b> Pre-Operational Testing
<b>Tab(s):</b> Welcome tab
Please use the checkbox(es) to verify the following information was submitted to the GSDT: <input checked="" type="checkbox"/> Proposed pre-operational testing program [40 CFR 146.82(a)(8) and 146.87]

## 7 Well Operation

This section is meant to provide a brief overview of the well operation conditions. Further details on the well operation program are provided in (Attachment 6: Well Operations, 2022).

### 7.1 Operational Procedures [40 CFR 146.82(a)(10)]

Table 22 displays the operational parameters that will be used during injection operations. Details on the methods of calculations and inputs for these values are provided in (Attachment 6: Well Operations, 2022). Values provided in this table are designed to stay below the critical fracture pressure, while also managing the pressure loading experienced during operations to protect equipment. It is not anticipated that significant deviation from these values will occur during the life of the project.

Table 22. Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface	2,051	psi
Downhole	2,358	psi
Maximum Injection Mass		
Annual	450	kt
30-year Project	13,500	kt
Average Injection Rate		
Mass Injection Rate	856	kg/min

Parameters/Conditions	Limit or Permitted Value	Unit
Volumetric Injection Rate	565	gal/min
	19,368	barrels/day
Annulus Pressure		
Maximum	1,500	psi
Minimum	-5	psi
Operational	100	psi

## 7.2 Proposed CO<sub>2</sub> Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

Cardinal Ethanol will analyze the CO<sub>2</sub> stream during the injection phase of the project to provide data representative of its chemical characteristics and to meet the requirements of 40 CFR 146.90 (a). Details on the testing and monitoring of the CO<sub>2</sub> stream are provided in the testing and monitoring section of this permit. Additional details on technical standards, QA/QC policy, sample collection and storage policies, and analytical methods are provided in the QASP (Attachment 11: QASP, 2022).

Based on the nature of the ethanol fermentation process, the CO<sub>2</sub> stream produced is anticipated to be of high purity. Even so, after fermentation, the CO<sub>2</sub> stream will pass through two scrubbers prior to entering the compressor and the pipeline.

It is currently anticipated that quarterly sampling of the CO<sub>2</sub> injection stream will be sufficient to accurately track the composition of the stream. The regular samples will be taken on quarterly intervals, at the end of each quarter (March, June, September, and December).

## 8 Testing and Monitoring

Testing and Monitoring GSDT Submissions
<b>GSDT Module:</b> Project Plan Submissions <b>Tab(s):</b> Testing and Monitoring tab  Please use the checkbox(es) to verify the following information was submitted to the GSDT: <input checked="" type="checkbox"/> Testing and Monitoring Plan [40 CFR 146.82(a)(15) and 146.90]

This section is meant to provide a brief overview of the Testing and Monitoring Plan. Further details on the well operation program are provided in (Attachment 7: Testing And Monitoring, 2022).

## 9 Injection Well Plugging

Following the conclusion of injection operations, the injection well will be permanently plugged and abandoned. Details on the methods of these operations are provided in (Attachment 8: Well Plugging, 2022). The methods and procedures presented in the attachment are consistent with industry standards and the requirements detailed in 40 CFR 146.92. All materials to be used for the plugging and abandonment are suitable for the anticipated corrosive loading below the top of the Eau Claire. Above the top of the Eau Claire Formation, the materials are standard construction materials, conforming the API specifications.

### Injection Well Plugging GSDT Submissions

**GSDT Module:** Project Plan Submissions

**Tab(s):** Injection Well Plugging tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ Injection Well Plugging Plan [40 CFR 146.82(a)(16) and 146.92(b)]

## 10 Post-Injection Site Care and Site Closure

The requested documents listed below have been included in the file submission (Attachment 9: Post-Injection Site Care, 2022). These documents address the rule requirements for the above EPA citations. The Hoosier #1 Project is requesting an alternative PISC timeframe.

### PISC and Site Closure GSDT Submissions

**GSDT Module:** Project Plan Submissions

**Tab(s):** PISC and Site Closure tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ PISC and Site Closure Plan [40 CFR 146.82(a)(17) and 146.93(a)]

**GSDT Module:** Alternative PISC Timeframe Demonstration

**Tab(s):** All tabs (only if an alternative PISC timeframe is requested)

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ Alternative PISC timeframe demonstration [40 CFR 146.82(a)(18) and 146.93(c)]

## 11 Emergency and Remedial Response

The below requested documents have been included in the file submission (Attachment 10: ERRP, 2022). These documents address the rule requirements for the above EPA citations.

### Emergency and Remedial Response GSDT Submissions

**GSDT Module:** Project Plan Submissions

**Tab(s):** Emergency and Remedial Response tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ Emergency and Remedial Response Plan [40 CFR 146.82(a)(19) and 146.94(a)]

## 12 Injection Depth Waiver and Aquifer Exemption Expansion

Cardinal and Vault do not intent to apply for a Depth Waiver or Aquifer Exemption. As such, no supplemental documents have been filed.

### Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions

**GSDT Module:** Injection Depth Waivers and Aquifer Exemption Expansions

**Tab(s):** All applicable tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☐ Injection Depth Waiver supplemental report [40 CFR 146.82(d) and 146.95(a)]

☐ Aquifer exemption expansion request and data [40 CFR 146.4(d) and 144.7(d)]

## 13 Risk Assessment

Development of both a Project Risk Assessment (RA) and a Risk Management Plan (RMP) are critical to advancement of a carbon sequestration project. These plans will be dynamic and evolve over time through the pre-injection, operational, and PISC phases of a project as new data are acquired and assessed. One primary goal of conducting an RA early in the feasibility and characterization phase of a project is to identify potential risk scenarios that can be managed through site characterization along with testing and monitoring activities. As such, the RMP will be closely linked to the Pre-Operational and Testing and Monitoring Plans throughout all phases of the project's life cycle (Figure 52). Initially, the RMP will identify areas of subsurface uncertainty, which will help determine the site characterization and development activities, as well as to identify any potential long-term risk scenarios that can be managed and mitigated through testing and monitoring activities.

The geologic characterization studies, static modeling, and computational modeling work were used to inform the risk assessment and scenario ranking for the Hoosier #1 Project (Figure 52). A high-level list of sixty risk scenarios was compiled based on Vault's experience working on RAs for over a dozen carbon sequestration projects in North America. The risk scenarios were ranked individually on severity and likelihood scale that each ranged from one to five. All the risk scenarios ranked between two and eight out of a possible 25.

Table 23 provides a description of the risk rank categories, associated color code, and description. Thirty-seven of the risk scenarios can be managed and mitigated through site characterization and testing and monitoring activities.

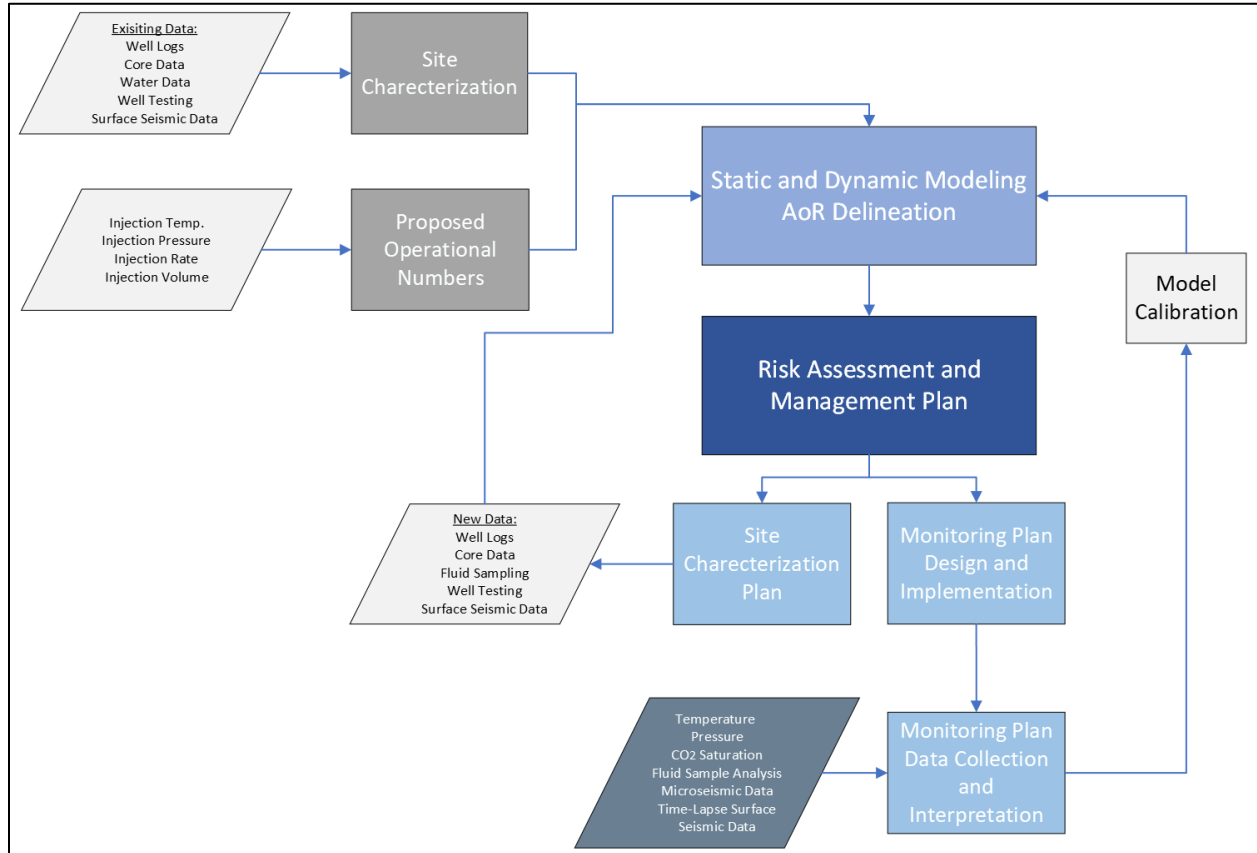


Figure 52: Workflow from initial site characterization for a project through to testing and monitoring plan design.

**Table 23: Risk rank categories, associated color coding, and description**

<b>Risk Rank</b>	<b>Color Code</b>	<b>Description</b>
20 – 25	Black	Non-Operable: Evacuate the zone or area
10 – 16	Red	Intolerable: Do not take this risk
5 – 9	Yellow	Undesirable: Demonstrate as low as reasonably possible (ALARP) before proceeding
2 – 4	Green	Acceptable: Proceed carefully with continuous improvement
1	Blue	Negligible: Safe to Proceed

Table 24 summarizes the risk rankings, high-level risk scenario categories, and the number of scenarios that fit into each category. The risk scenario categories cover subsurface elements such as geology, containment, injectivity, geochemical effects, and potential for induced seismicity events. Table 1 in Risk Register contains a full list of the 60 risk scenarios and rankings (Attachment 12: Confidential Business Information: Risk Register, 2022).

**Table 24: Breakdown of the risk rankings, categories, and number of scenarios identified.**

<b>Ranking</b>	<b>Risk Category</b>	<b>Scenarios Identified</b>
Undesirable (5 – 9)	Schedule	3
	Regulatory	1
	Geology	5
	Geology: Containment	2
	Opposition: Public	8
	Economic	1
	Project Wells: Drilling	1
	Reservoir Performance	1
	Monitoring: General	2
Acceptable (2 – 4)	Geology	5
	Geology: Containment	1
	Reservoir Performance	2
	Project Management	3
	CO <sub>2</sub> Injectate	1
	Project Wells: Drilling	2
	Project Wells: Operations	1
	Project Wells: Integrity	3
	Project Wells: Completions	1
	Existing Wells	3
	Monitoring: General	6
	Weather	1

Ranking	Risk Category	Scenarios Identified
	Liability	1
	Regulatory	1
Negligible (1)	Project Wells: Operations	4
	Geology	1
<b>Total</b>		<b>60</b>

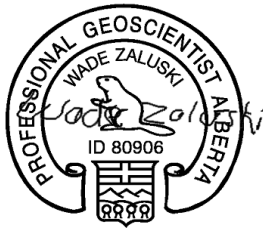
Thirty-two of the risk scenarios identified can be managed and mitigated through the pre-operational testing program that will be executed when the project wells are drilled. The data collected over this phase will be used to manage and mitigate uncertainties and risks related to capacity, containment, injectivity, injection pressures and fracture gradient, as well as potential seismic events (Attachment 12: Confidential Business Information: Risk Register, 2022).

Thirty-two of the risk scenarios identified can be managed and mitigated through testing and monitoring activities that will be implemented through the injection and PISC phases of the project. The project Risk Register summarizes the risk scenarios with their associated testing and monitoring mitigations (Attachment 12: Confidential Business Information: Risk Register, 2022).

Plan revision number: N/A  
Plan revision date: July 4, 2022

## 14 Approval

Wade Zaluski P.Geo.



May 31, 2022

APEGA Permit to Practice Number Vault4401  
P15447

## 15 References

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## Class VI UIC Area of Review and Corrective Action

This submission is for:

Project ID: R05-IN-0003

Project Name: Project Hoosier #1

Current Project Phase: Pre-Injection Prior to Construction

### Overview

Simulator Used for AoR delineation modeling: GEM

Version Used: CMG's GEM Compositional Model - V 2021.10

Simulator Description/Documentation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Simulation\\_Description\\_Documentation.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Simulation_Description_Documentation.pdf)

Description of File Contents: The file submitted contains a summary of the main features of GEM, as provided in the CMG documentation.

Total Simulation Time From Start of Injection: 30 yrs

Additional AoR Delineation Information: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Additional--Information.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Additional--Information.pdf)

Description of Information Submitted: Indiana is not a primacy state. No additional requirements

### Model Domain

Coordinate System: State Plane

Horizontal Datum: NAD83

Coordinate System Units: ft

Vertical Datum: Other

Describe Vertical Datum: ft Below Mean Sea level (ft bsml)

Zone: NAD 83 Indiana East - 2965

FIPZONE: 1301 ADSZONE: 3826

Mesh Type: Other

Describe Mesh Type: Proportional

Domain Size in Global Units Specified Above

Domain Coordinates File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/AoRModeling\\_DomainCoordTemplate.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/AoRModeling_DomainCoordTemplate.pdf)

Grid Size

Number of Nodes in x: 420 y: 420 z: 189

Grid Spacing: Constant

Grid Spacing in x: 100 y: 100 z: 4

Grid File Format: ASCII file containing vertices and elements

Grid File Description: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Grid--File--Description.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Grid--File--Description.pdf)

Grid Data File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Sub\\_Model\\_2-18-22\\_2B.dat](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Sub_Model_2-18-22_2B.dat)

Faults Modeled: No

Caprock Modeled: Yes

Image File(s) for Model Domain Grid: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Model--Domain--Grid--Images.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Model--Domain--Grid--Images.pdf)

### Processes Modeled by Simulator

Reservoir Conditions:

Supercritical CO2 Conditions

Phases Modeled:

Aqueous Supercritical CO2 Precipitated Salt

Aqueous Phase:

Phase Compressibility: Compressible

Compressibility Value: 3 1/Pa

Phase Composition: Compositional

Aqueous Phase Components:

CO2 Water Methane

Supercritical CO2 Phase:

Phase Compressibility: Compressible

Phase Composition: Compositional

Supercritical CO2 Phase Components:

CO2 Water Methane

Equation of State Description Including Reference: GEM utilizes either the Peng-Robinson or the Soave- Redlich-Kwong equation of state to predict the phase equilibrium compositions and densities of the oil and gas phases, and supports various schemes for computing related properties such as oil and gas viscosities. The quasi-Newton successive substitution method, QNSS, as developed at CMG, is used to solve the nonlinear equations associated with the flash calculations. A robust stability test based on a Gibbs energy analysis is used to detect single phase situations. GEM can align the flash equations with the reservoir flow equations to obtain an efficient solution of the equations at each timestep. CMG's WinProp equation of state software can be used to prepare EOS data for GEM. The Peng-Robinson EOS was used in this model.

File with EOS Reference or Documentation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/File\\_with\\_EOS\\_Reference\\_or\\_Documentation.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/File_with_EOS_Reference_or_Documentation.pdf)

Multifluid Flow Processes:

Advection Dispersion Diffusion Buoyancy

Non-wetting Fluid Trapping Pore Compressibility

Thermal Conditions: Non-Isothermal

File Describing Thermal Conductivity Function including Parameters: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/GEM\\_Thermal\\_Option.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/GEM_Thermal_Option.pdf)

Heat Transport Processes:

Advection Diffusion Conduction

Geochemistry Modeled: Yes

File Describing Geochemistry Modeling: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Geochemistry\\_Modeling.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Geochemistry_Modeling.pdf)

Geomechanical/Structural Deformations Modeled: Yes

File Describing Geomechanical/Structural Modeling: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Geomechanical\\_Structural\\_Deformation\\_Modeling.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Geomechanical_Structural_Deformation_Modeling.pdf)

## Rock Properties and Constitutive Relationships

Porosity/Permeability Model

Single Porosity

Porosity Distribution: Heterogeneous

Spatially Variable Porosity File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Sub\\_Model\\_2-18-22\\_2B-----Por.dat](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Sub_Model_2-18-22_2B-----Por.dat)

File Describing how Porosity was Determined and Assigned to Numerical Model: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Porosity--Assignment--Method--for--Numerical--Model.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Porosity--Assignment--Method--for--Numerical--Model.pdf)

Image Files for Porosity Distributions: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por--Distribution--Images.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por--Distribution--Images.pdf)

Permeability Distribution: Heterogeneous

Spatially Variable Permeability File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Sub\\_Model\\_2-18-22\\_2B-----Perm.dat](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Sub_Model_2-18-22_2B-----Perm.dat) mD

File Describing how Permeability was Determined and Assigned to Numerical Model: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Permeability--Assignment--Method--for--Numerical--Model.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Permeability--Assignment--Method--for--Numerical--Model.pdf)

Image Files for Permeability Distributions: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm--Distribution--Images.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm--Distribution--Images.pdf)

Number of Rock Types Modeled: 3

Description of Rock Type Selection and Assignment: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rock--Type--Assignment--Method--for--Numerical--Model.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rock--Type--Assignment--Method--for--Numerical--Model.pdf)

Rock Type Distribution Data File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rock--Type--Data.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rock--Type--Data.pdf)

Image Files for Rock Type Distribution: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rock--Type--Images.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rock--Type--Images.pdf)

### Rock Type #1

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value

Compressibility Value: 0.000007 1/psi

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Functional Form

File Describing Functional Form Used for Aqueous Saturation vs Capillary Pressure:

[https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Cap\\_Pressure\\_1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Cap_Pressure_1.pdf)

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Table

Tabular Format File for Aqueous Relative Permeability: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Aq_1.csv)

[PreConstruction/AoRModeling-07-08-2022-1544/Rel\\_Perm\\_Table\\_Aq\\_1.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Aq_1.csv)

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Table

Tabular Format File for Gas Relative Permeability: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Gas_1.csv)

[PreConstruction/AoRModeling-07-08-2022-1544/Rel\\_Perm\\_Table\\_Gas\\_1.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Gas_1.csv)

Hysteresis other than non-wetting fluid trapping: No

Porosity and Permeability Reduction Due to Salt Precipitation

File Describing Function for Porosity Reduction Due to Salt Precipitation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por\\_Salt\\_Precip\\_1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por_Salt_Precip_1.pdf)

File Describing Function for Permeability Reduction Due to Salt Precipitation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm\\_Salt\\_Precip\\_1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm_Salt_Precip_1.pdf)

### Rock Type #2

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value

Compressibility Value: 0.000007 1/psi

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Functional Form

File Describing Functional Form Used for Aqueous Saturation vs Capillary Pressure:

[https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Cap\\_Pressure\\_2.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Cap_Pressure_2.pdf)

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Table

Tabular Format File for Aqueous Relative Permeability: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Aq_2.csv)

[PreConstruction/AoRModeling-07-08-2022-1544/Rel\\_Perm\\_Table\\_Aq\\_2.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Aq_2.csv)

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Table

Tabular Format File for Gas Relative Permeability: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Gas_2.csv)

[PreConstruction/AoRModeling-07-08-2022-1544/Rel\\_Perm\\_Table\\_Gas\\_2.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Gas_2.csv)

Hysteresis other than non-wetting fluid trapping: No

Porosity and Permeability Reduction Due to Salt Precipitation

File Describing Function for Porosity Reduction Due to Salt Precipitation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por\\_Salt\\_Precip\\_2.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por_Salt_Precip_2.pdf)

File Describing Function for Permeability Reduction Due to Salt Precipitation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm\\_Salt\\_Precip\\_2.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm_Salt_Precip_2.pdf)

### Rock Type #3

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value

Compressibility Value: 0.000007 1/psi

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Functional Form

File Describing Functional Form Used for Aqueous Saturation vs Capillary Pressure:

[https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Cap\\_Pressure\\_3.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Cap_Pressure_3.pdf)

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Table

Tabular Format File for Aqueous Relative Permeability: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel\\_Perm\\_Table\\_Aq\\_3.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Aq_3.csv)

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Table

Tabular Format File for Gas Relative Permeability: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel\\_Perm\\_Table\\_Gas\\_3.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Rel_Perm_Table_Gas_3.csv)

Hysteresis other than non-wetting fluid trapping: No

Porosity and Permeability Reduction Due to Salt Precipitation

File Describing Function for Porosity Reduction Due to Salt Precipitation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por\\_Salt\\_Precip\\_3.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Por_Salt_Precip_3.pdf)

File Describing Function for Permeability Reduction Due to Salt Precipitation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm\\_Salt\\_Precip\\_3.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Perm_Salt_Precip_3.pdf)

Rock Properties Comments: Rock Type 1 - Silt Rock Type 2 - Silty Sandstone Rock Type 3 - Sandstone Capillary pressure not considered as data are not currently available, model will be updated based on results of core testing. Salt precipitation is a feature included in CMG modeling software, but has not been incorporated into this version of the model. The model will be updated based on the results from geochemical analysis.

## Boundary Conditions

Attach Boundary Conditions Description File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Boundary\\_Conditions.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Boundary_Conditions.pdf)

## Initial Conditions

Initial Phases in Domain: Aqueous

Initial Aqueous Pressure: Varying with Depth, Temperature, and Salinity

Initial Aqueous Pressure: 1189 psi at Reference Elevation: 3114 ft

Initial Temperature: Spatially Constant

Initial Temperature: 100 F

Initial Salinity: Spatially Constant

Initial Salinity: 120000 ppm

## Operational Information

Number of Injection Wells: 1

### Injection Well #1

Well Direction: Vertical

Location: X: -84.864284 Longitude (DD) Y: 40.186587 Latitude (DD)

Wellbore Diameter: Constant

Wellbore Diameter: 6.276 in

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 3179 Elevation of Bottom of Screened Interval: 3804 ft

Mass Rate of Injection: 0.45 MMT/yr

Total Mass of Injection: 13.5 MMT

Fracture Gradient: 0.84 psi/ft

Maximum Injection Pressure: 2369 psi Elevation Corresponding to Pressure: 3159 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined: Fracture pressure determined at top of Mt. Simon, using approx. 90% of 0.84 (0.75). Gradient was determined using offset SRT results (Lima UIC Project). Values will be updated following the results of the SRT to be run on the well.

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

[https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Frac\\_Pressure\\_Determination.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Frac_Pressure_Determination.pdf)

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 1/1/2023 Stop Date: 1/1/2023

Number of Production/Withdrawal Wells: 0

Operational Information Comments: Project intends to use one injection well, and 3 monitoring wells.

## Model Output/Results

Provide file name and corresponding spatial location for each file: Time series data showing the mineralization process over 100 years post injection, and the percentage of CO<sub>2</sub> Super-Critical, CO<sub>2</sub> dissolved, and CO<sub>2</sub> Trapped over 50 years post injection. Also included is a CSV file with the requested time series data

Time-Series File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Time--Series--Data.zip](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Time--Series--Data.zip)

Provide file name and corresponding variable and time stamp for each file: Model snapshot data showing the CO<sub>2</sub> and pressure plumes after 30 years of injection. Additionally, files for the CO<sub>2</sub> phases and distribution are also included. A .out file displays the actual modeling output containing the requested information.

Snapshot File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Snapshot--Data.zip](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Snapshot--Data.zip)

Provide file name and corresponding description of surface for each file: The attached file shows the water efflux into the aquifer over time. This demonstrates the efficacy of the analytical Carter-Tracy aquifer model.

Surface Flux File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Aquifer\\_Flux.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Aquifer_Flux.csv)

## AoR Pressure Front Delineation

Lowermost USDW:

Name of Lowermost USDW: Maquoketa

Water Density: 1.0083 gm/cm<sup>3</sup> at Elevation: 450 ft

Location of Measurement for Density: NA - estimated from other UIC applications

Temperature: 63 F at Elevation: 450 ft

Location of Measurement: NA - estimated from other UIC applications

Pressure: 171 psi at Elevation: 450 ft

Location of Measurement: NA - estimated from other UIC applications

Salinity: 5000 ppm at Elevation: 450 ft

Location of Measurement: NA - estimated from other UIC applications

Elevation of bottom of USDW: 450 ft

Injection Zone:

Name of Injection Zone: Mt. Simon

Water Density: 1.0731 gm/cm<sup>3</sup> at Elevation: 3159 ft

Location of Measurement: NA - estimated from other UIC applications

Temperature: 100 F at Elevation: 3159 ft

Location of Measurement: NA - estimated from other UIC applications

Pressure: 1183 psi at Elevation: 3159 ft

Location of Measurement: NA - estimated from other UIC applications

Salinity: 120000 ppm at Elevation: 3159 m

Location of Measurement: NA - estimated from other UIC applications

Elevation of top of Injection Zone: 3159 ft

Method of Estimating Critical Pressure: Static Mass Balance

Assumptions: Linear pressure profile, uniform density

File Describing Critical Pressure Estimation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Method\\_of\\_Estimating\\_Critical\\_Pressure.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Method_of_Estimating_Critical_Pressure.pdf)

Estimated Critical Pressure: 227 psi

Delineated AoR:

Shapefile or KML File Showing Delineated AoR: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Simulation--Rescue.7z](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/Simulation--Rescue.7z)

AoR Pressure Front Delineation Comments: The pressure plume was determined by calculating the critical delta pressure and including all gridblocks from the simulation model that exceeded that value after 30 years of injection. The maximum pressure plume radius was determined by calculating the distance from the wellbore to the furthestmost gridblock that exceeded the critical delta pressure. The pressure plume is irregular in shape due to the heterogeneity and dip of the reservoir. The AoR was

determined by adding 0.5 miles to the maximum pressure plume radius, as a safety factor.

## Corrective Action

File with Location of All Penetrations within AoR: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/File--with--location--of--all--penetrations--within--AoR.csv](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/File--with--location--of--all--penetrations--within--AoR.csv)

Supporting Documentation: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/CardinalWellsComp--Abn.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/CardinalWellsComp--Abn.pdf)

Corrective Action Comments: No corrective action is required on any of the wells within the AoR.

## Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b) or applicable state requirements]

Are you making an Area of Review and Corrective Action Plan submission at this time?: Yes

Reason for Project Plan Submission: Permit application submission

Project Plan Upload

Attach the Area of Review and Corrective Action Plan: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/2.-AoR--and--Corrective--Action--Plan\\_Hoosier--1\\_noCBI.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/AoRModeling-07-08-2022-1544/2.-AoR--and--Corrective--Action--Plan_Hoosier--1_noCBI.pdf)

Appendices and Supporting Materials Upload

## Area of Review Reevaluation [40 CFR 146.84(e) or applicable state requirements]

Minimum fixed frequency of AoR reevaluation: 5 Years

Are you making an Area of Review reevaluation submission at this time?: No

Reevaluation Background

Reevaluation Materials

Please upload your amended AoR and Corrective Action Plan on the previous tab.

## Complete Submission

Authorized submission made by: Ricky Weimer

Comments regarding this submission: Results of simulations/model will be updated following the results of field testing and well installation.

For confirmation a read-only copy of your submission will be emailed to: [craig@vault4401.com](mailto:craig@vault4401.com)

**AREA OF REVIEW AND CORRECTIVE ACTION PLAN  
40 CFR 146.84(b)**

**HOOSIER #1 PROJECT**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
866-559-6026, jeremeyherlyn@cardinalethanol.com

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
Well Location for CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

Several figures contained within this document contain Confidential Business Information (CBI) that is privileged and exempt from public disclosure – “Narrative without CBI”. These images will be delivered to the United States (US) Environmental Protection Agency (EPA) in a separate document – “Narrative with CBI”.

The figures listed below contain CBI and have been redacted from the publicly disclosed version of this document:

Figure 5: Confidential Business Information: Well log upscaling.

Figure 6: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey).

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### **List of Acronyms**

2D	Two-dimensional
3D	Three-dimensional
AoR	Area of Review
BHP	Bottomhole Pressure
CCS	Carbon Capture and Sequestration
CCS1	Injection Well
CH <sub>4</sub>	Methane
CMG	Computer Modeling Group
CO <sub>2</sub>	Carbon Dioxide
EOS	Equation of State
EPSG	European Petroleum Survey Group
FT	Feet
FBSL	Feet Below Sea Level
GEM	Generalized Equation Model
H <sub>2</sub> O	Water
IDNR	Indiana Department of Natural Resources
IGWS	Indiana Geological and Water Survey
kv/kh ratio	vertical permeability divided by horizontal permeability
kh	Horizontal Permeability
kv	Vertical Permeability
MIT	Mechanical Integrity Test
MSL	Mean Sea Level
O&G	Oil and Gas
OBS1	Deep Observation Well
OCP	One Carbon Partnership, LLC
P&A	Plugged and Abandoned
PNL	Pulsed Neutron Logging
PSI/FT	Pounds per Square Inch per Foot
PSIA	Pounds per Square Inch Absolute
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

This document describes how the geologic and hydrologic information were used to delineate the Area of Review (AoR). It also addresses the extent to which the Hoosier #1 Project needs to undertake corrective actions for features within the AoR that may penetrate the confining zone, and how such corrective actions will be taken if needed in the future. Section 1.1 describes the computational model that was used to delineate the AoR, including a description of the simulator and the physical processes modeled and a description of the conceptual model and numerical implementation. It also describes the AoR, and how the AoR will be re-evaluated over time. Section 4 describes the Hoosier #1 Project Corrective Action Plan. This document is intended to demonstrate compliance with 40 CFR 146.84.

## 1 Computational Modeling Approach (40 CFR 146.84(b)(1))

### 1.1 Model Background

#### 1.1.1 Static Model

The Hoosier#1 project made use of two models (Figure 1). The first was a static model which incorporated local and regional data in a single model. The second was a smaller computational model. The model was developed using Rock Flow Dynamics' software tNavigator. Table 1 summarizes the steps and the workflow used to generate the final structural and static model.

**Table 1: Summary of static modeling steps**

Modeling Step	Input Data	Information
Injection and Confining Zone Details	<ul style="list-style-type: none"> <li>Core data from nine wells and well log data were downloaded from public data sources</li> <li>Class I injection wells were used as calibration points</li> </ul>	<ul style="list-style-type: none"> <li>Facies, porosity, and permeability of the Eau Claire Formation and Mt. Simon Sandstone</li> <li>Petrophysical properties</li> </ul>
Incorporate two-dimensional (2D) Seismic Survey	<ul style="list-style-type: none"> <li>Three 2D surface seismic lines</li> </ul>	<ul style="list-style-type: none"> <li>Local detail of geologic structures</li> </ul>
Formation Surfaces and Thickness	<ul style="list-style-type: none"> <li>Well logs</li> </ul>	<ul style="list-style-type: none"> <li>Regional geologic structure</li> </ul>
Static Model	<ul style="list-style-type: none"> <li>Data above</li> </ul>	<ul style="list-style-type: none"> <li>Develop a model to represent subsurface facies, porosity, and permeability</li> </ul>
Computational Model	<ul style="list-style-type: none"> <li>Static model</li> </ul>	<ul style="list-style-type: none"> <li>CO<sub>2</sub> and pressure plume behavior</li> </ul>

The formations or zones that were modeled and the number of layers in each zone have been summarized in Table 2. Figure 2 and Figure 3 show the stratigraphic column of horizons while Figure 2 and Figure 4 displays the zones used in the static model. The deepest underground source of drinking water (USDW) is plotted on these cross sections and is discussed in detail in the Project Narrative (Attachment 1: Narrative, 2022).

The static model was 141 miles (east-west) by 116 miles (north-south). The area was selected to include wells in the region that had reliable petrophysical data. The model contains 24.4 million cells. The static model cell size was selected to represent the subsurface heterogeneity and keep the cell count small enough to manageably run the computational modeling. Thinner cells were used in the injection zone where the computational modeling was focused on the CO<sub>2</sub> injection.

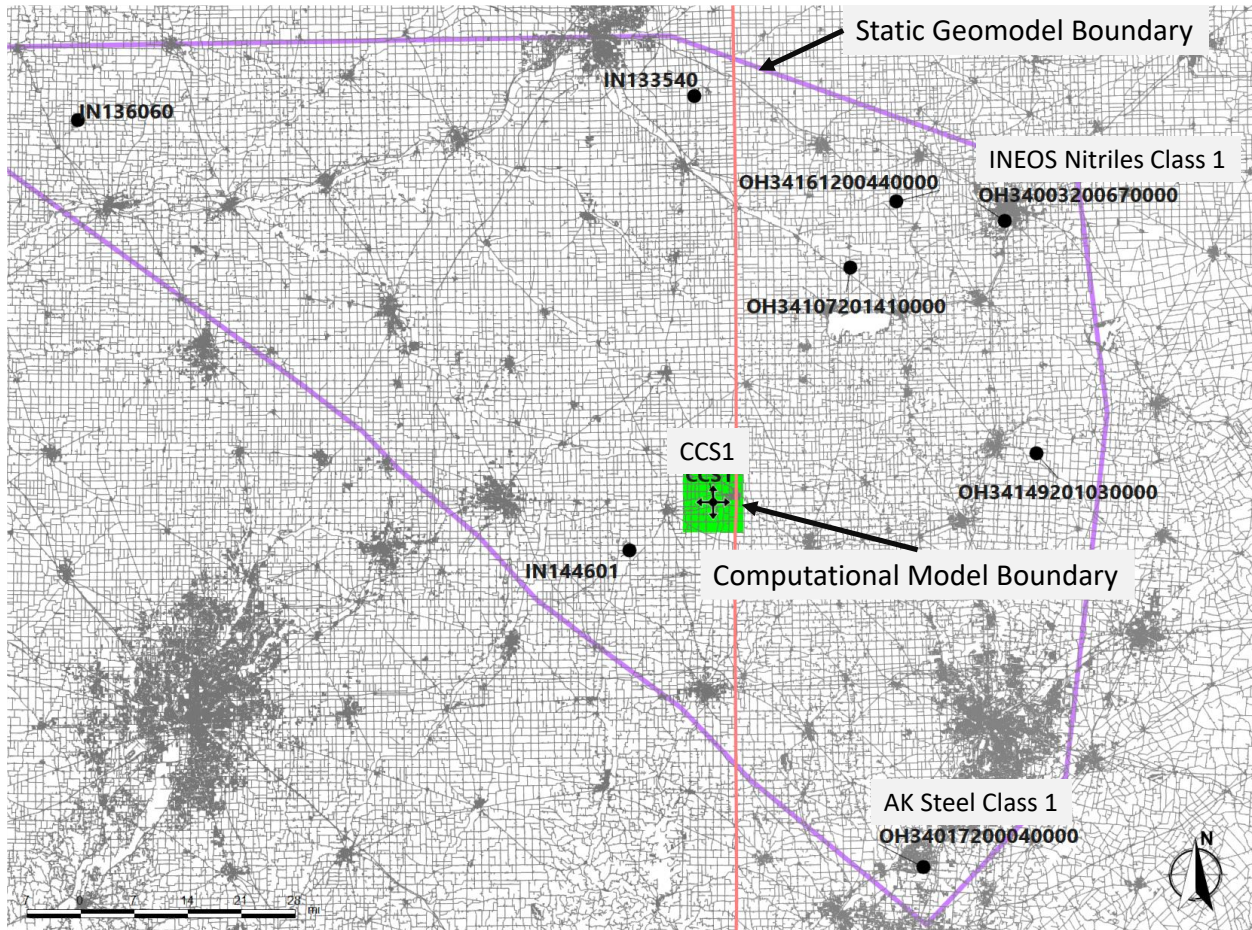


Figure 1: Areas covered by the static and computational models

**Table 2: Table of static model formations**

<b>Formation (Zone)</b>	<b>Layer Type</b>	<b>Number of Model Layers</b>	<b>X-Y Cell Length</b>	<b>Porosity and Permeability Data Source</b>
Undifferentiated	Proportional	1	500ft	Not modeled
Trenton Limestone		1		Not modeled
Knox Formation		1		Not modeled
Davis Formation		1		Not modeled
Eau Claire Formation		150		Well logs and Class I wells
Mt Simon Sandstone		125		Well logs and Class I wells
Precambrian Basement		40		Not modeled

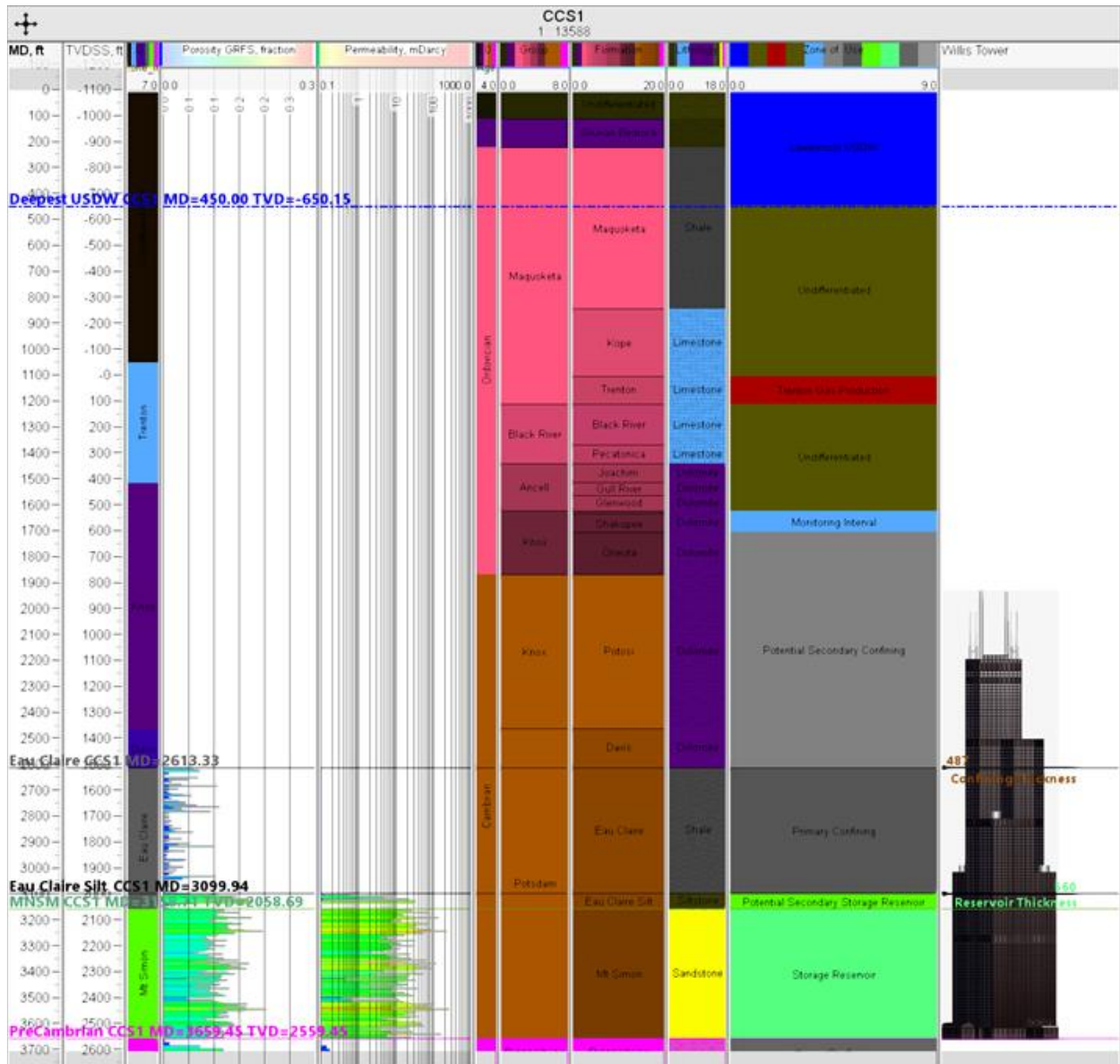


Figure 2: CCS1 modeling stratigraphic column

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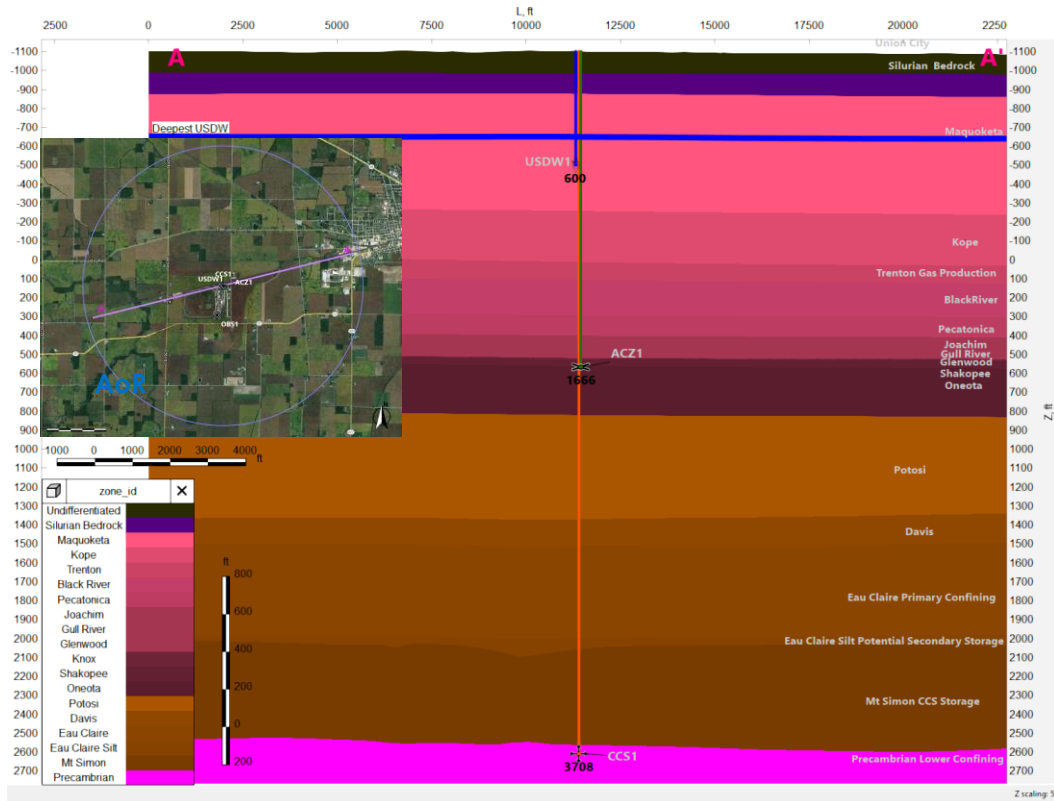


Figure 3: Cross Section A-A' stratigraphic formations.

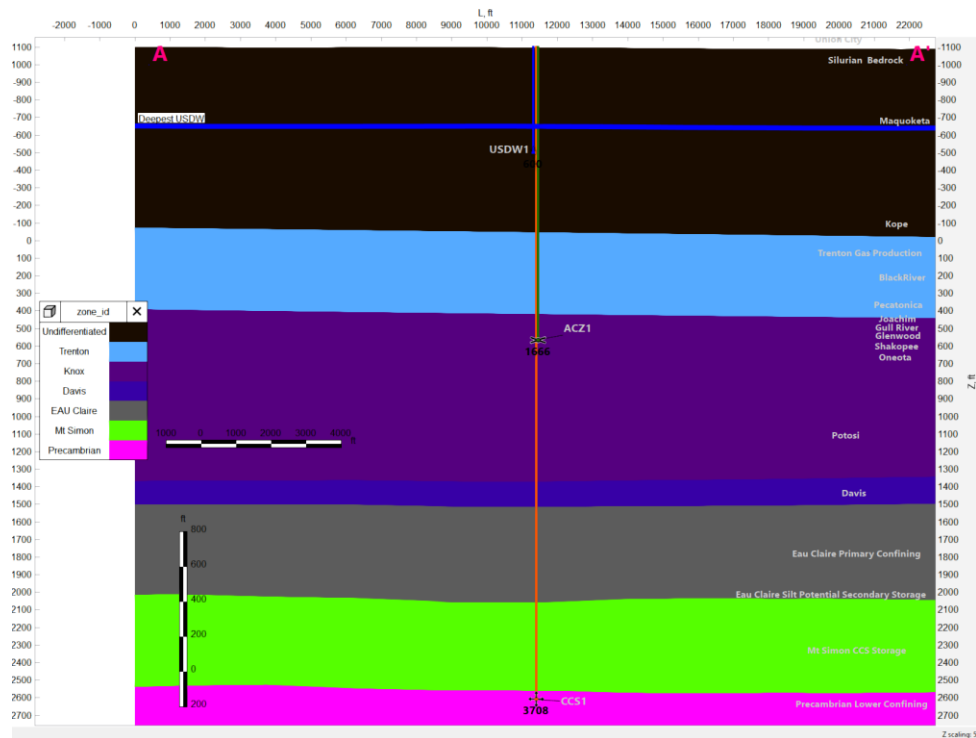


Figure 4: Cross Section A-A' static model formations.

### ***1.1.2 Computational Model***

Numerical simulation of carbon dioxide (CO<sub>2</sub>) injection into deep geologic formations requires the modeling of complex, coupled hydrologic, chemical, and thermal processes including multi-fluid flow and transport, partitioning of CO<sub>2</sub> into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. The fluid flow model used for this application is Generalized Equation Model (GEM), a commercial simulator developed by Computer Modelling Group (CMG) of Calgary, Alberta.

GEM has been developed by CMG over many years primarily for modeling hydrocarbon reservoirs. This simulation software was selected because it has many advanced features for carbon sequestration modeling including relative permeability hysteresis, CO<sub>2</sub> solubility in water, water vaporization, geochemistry, mineralization, thermal, and geomechanical properties.

For this application, an equation of state (EOS) was developed with three components: CO<sub>2</sub>, methane (CH<sub>4</sub>), and water (H<sub>2</sub>O). Since the computational model was originally designed for hydrocarbon reservoirs, it requires a hydrocarbon component (CH<sub>4</sub>), but it is only present as a trace component. The phases modeled are supercritical CO<sub>2</sub>, dissolved CO<sub>2</sub> in water, residual CO<sub>2</sub> (gas trapping), and CO<sub>2</sub> trapped by mineralization.

The model uses well established discretized fluid flow equations and an adaptive-implicit method for solving the resulting sparse matrix. Details can be found in the following publications: (Collins, D.A., Nghiem, L.X., Li, Y.-K. and Grabenstetter, J.E., May 1992), (Thomas, G.W. and Thurnau, D.H., October 1983), (Nghiem, L.X. and Li, Y.-K., September 4-8, 1989)

The model uses a cubic EOS with Peng-Robinson (PR) coefficients. Viscosity modeling is accomplished by using either the Jossi-Stiel-Thodos or Pedersen correlations. Key assumptions include:

- Eccentricity of molecules
- Use of random mixing rules
- Binary interaction parameter
- Minimum Gibbs energy as an equilibrium criterion
- Fugacity as a function of measurable properties
- Volume translation used to improve density prediction

The processes that were modeled for this application are:

- Convective and dispersive flow
- Relative permeability hysteresis
- Gas solubility in aqueous phase
- H<sub>2</sub>O vaporization
- Mineralization

It is also possible to assess the confining layer integrity using geomechanics. An initial evaluation was conducted using data from the literature; this evaluation will be updated when data from the injection or monitoring wells has been acquired.

Table 3 describes all of the processes used in the computational modeling to model CO<sub>2</sub> trapping within the injection zone. All of these primary processes were included in the initial model. No new mechanisms are anticipated.

**Table 3: Processes captured in the computational modeling**

<b>Computational Modeling Processes</b>	<b>Description</b>
Convective Flow	Movement of CO <sub>2</sub> through the pore space during the injection period
Dispersive Flow	Result of gravity segregation and increasing CO <sub>2</sub> solubility in water
Relative Permeability Hysteresis	Trapping of CO <sub>2</sub> in pore spaces as a result of imbibition (increase in wetting phase saturation), which occurs during gravity segregation
CO <sub>2</sub> Solubility	Modeled by a modified form of Henry's law
H <sub>2</sub> O Vaporization	Can occur around the wellbore as a result of high gas velocities and can lead to salt precipitation
Mineralization	Long-term trapping mechanism that occurs over thousands of years

The computational model is a subset of the static model, as it is not required to be as laterally extensive. The computational model is 7.9 miles (east-west) by 7.9 miles (north-south) and uses smaller 100 ft cells for horizontal gridding. The vertical layering remained consistent. The computational modeling focused on the Eau Claire Shale and the Mt Simon Sandstone.

## **1.2 Site Geology and Hydrology**

All information regarding the site geology and hydrology are provided in the Project Narrative (Attachment 1: Narrative, 2022). This includes the associated figures such as geologic maps, hydrologic maps, cross sections, and local stratigraphic columns.

### 1.3 Model Domain

Model domain information is summarized in Figure 1, Table 4, and Table 5.

**Table 4: Static Model domain information.**

Static Model Domain Information			
Coordinate System	Indiana East European Petroleum Survey Group (EPSG) 2965		
Horizontal Datum	Indiana East EPSG 2965		
Coordinate System Units	feet		
Zone	Indiana East EPSG 2965		
FIPZONE	-	ADSZONE	-
Coordinate of X min	57216	Coordinate of X max	824716
Coordinate of Y min	1511167	Coordinate of Y max	2123667
Elevation of bottom of domain (fbsl)	3967	Elevation of bottom of domain	-1187

**Table 5: Computational Model domain information.**

Computational Model Domain Information			
Coordinate System	Indiana East EPSG 2965		
Horizontal Datum	Indiana East EPSG 2965		
Coordinate System Units	feet		
Zone	Indiana East EPSG 2965		
FIPZONE	-	ADSZONE	-
Coordinate of X min	530951	Coordinate of X max	572951
Coordinate of Y min	1778776	Coordinate of Y max	1820776
Elevation of bottom of domain (fbsl)	2681	Elevation of bottom of domain	1926

A horizontal grid cell size of 500 feet (ft) was used. For the vertical cell size, proportional layering was used to generate cells approximately 4 ft high. The static model included horizons from ground level to the model base below the Precambrian horizon (Figure 4). Property modeling was focused on the Eau Claire Shale confining zone and the Mt Simon Sandstone injection zone.

### 1.4 Porosity and Permeability

#### 1.4.1 Petrophysical Well Log Upscaling

The Project Narrative includes a discussion of the wells in the region that provided important porosity and permeability data for the project as well as the petrophysical analysis that was completed on these wells (Attachment 1: Narrative, 2022). The well log data was upscaled and distributed into the static model.

In order to upscale well logs, an average algorithm is applied to the high-resolution well logs to produce one log value for each model cell that is penetrated by the well. Cell height plays a significant role in how porosity and permeability logs are upscaled and balances the capture of vertical heterogeneity while maintaining a manageable cell-count. Porosity values were upscaled into the grid using the arithmetic method (Figure 5).

The proportional vertical layering captured the variability observed in the porosity and permeability core data. The intent of this was to honor thin intervals in the injection zone that may represent significant permeability streaks, and thus play a significant role in dynamic reservoir behavior. The permeability upscaled cell was calculated from the equations in Figure 6. Figure 5 displays how the vertical variation of the wells with core was captured in the vertical property interpretation where there are data gaps.

**Figure 5: Confidential Business Information: Well log upscaling.**

**Figure 6: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey).**

### ***1.4.2 Facies and Petrophysical Modeling***

The upscaled core porosity from the nine wells provided high vertical resolution at each well for the static model; however, little was known about the porosity values between the wells. Therefore, variogram analysis was used to interpolate the data from the wells into the interwell space such that porosity represented the geological setting.

Facies were interpolated using the tNavigator Amazonas (Degterev, 2020) process that proved to be a reliable way to interpolate these facies data at these distances (Figure 7). The facies of the Eau Claire Formation consisted of primary shale with a thin layer of silty sandstone at the base which was modeled here to represent the Eau Claire Silt (potential secondary sequestration). The facies of the Mt Simon Sandstone were interpolated with two sandstone facies (Sandstone\_1 and Sandstone\_2). In the Precambrian, one facies was used. Figure 7 shows the facies thickness maps within the Mt Simon Sandstone and the Eau Claire Formation.

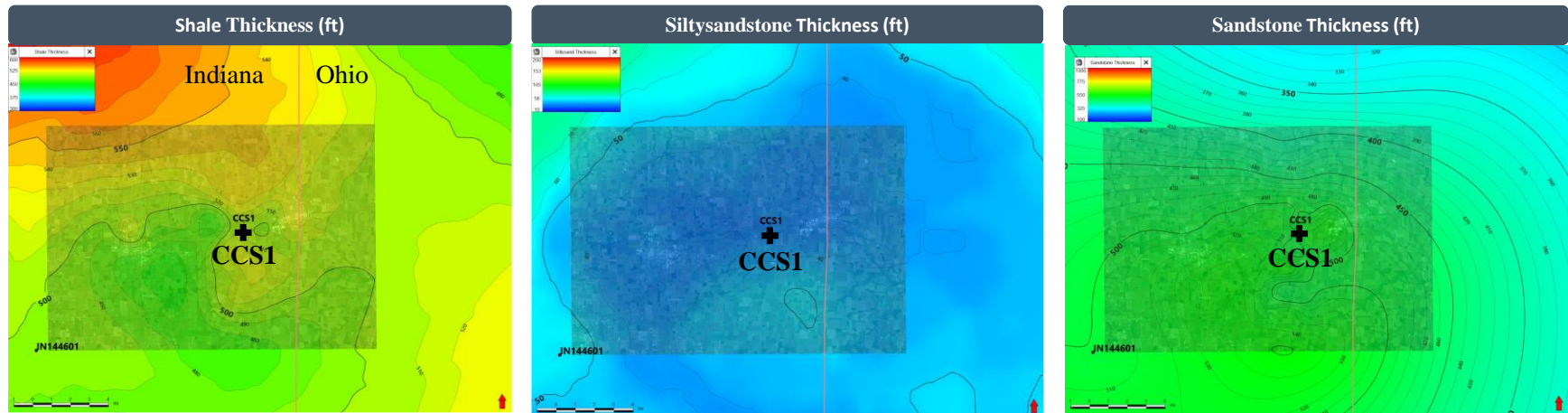


Figure 7: Facies thickness maps within the Mt. Simon Sandstone and Eau Claire Formation.

For each facies type, effective porosity was interpolated using Gaussian Random Function Simulation (GRFS) (Figure 8). Since the well data was sparse, a reliable horizontal variogram range and direction could not be extracted from variogram maps. To manage this issue, a horizontal variogram range of two miles was used in the horizontal direction. A vertical variogram range of approximately 10 feet was able to be extracted for each facies type. Figure 9 shows the relationship between the facies and effective porosity in the 3D model.

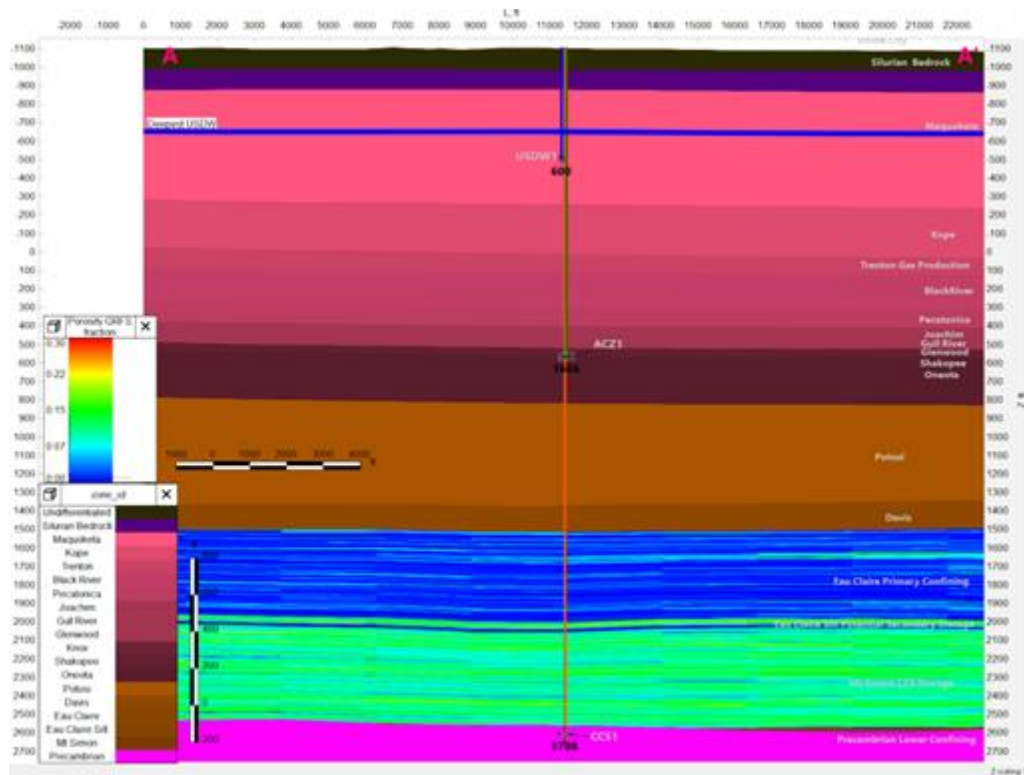


Figure 8: Cross Section A-A' formations and static model effective porosity.

The equations derived from Figure 6 were used to determine the effective porosity and permeability based on facies type (Figure 8 and Figure 10). The flow capacity of the injection zone can be characterized by the permeability-height product (kh) (Figure 11). The kh of the AoR compares favorably to the kh calculated from the fall-off test (FOT) reported in the INEOS (BP Lima) Nitrile disposal wells (INEOS USA LLC, 2015).

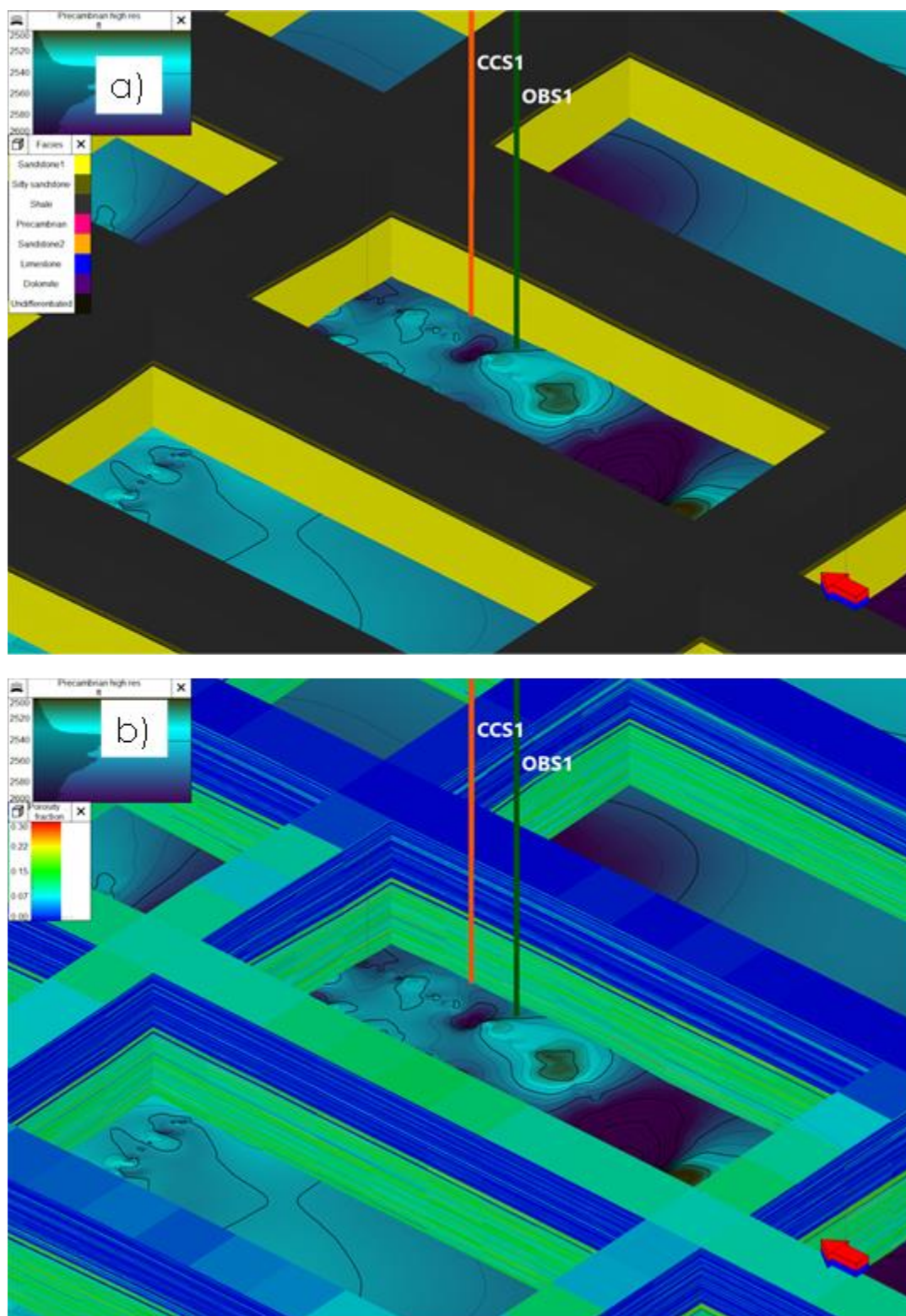


Figure 9: 3D view of static model showing a) facies, b) effective porosity.

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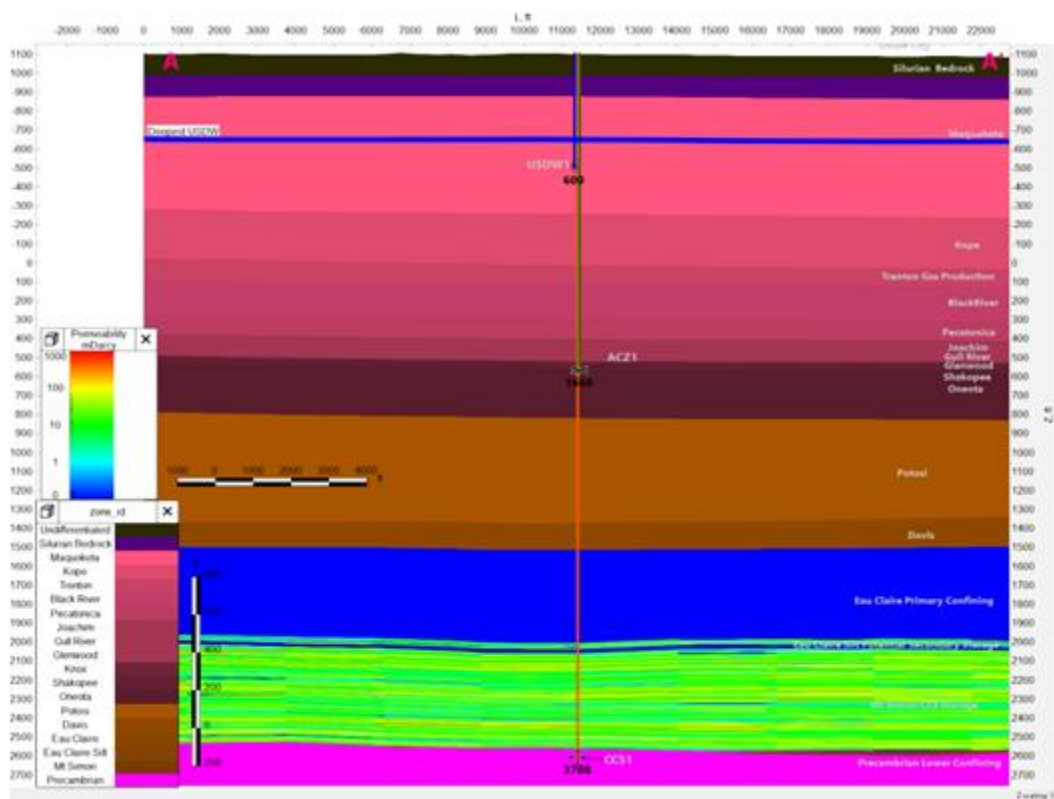


Figure 10: Cross Section A-A' formations and static model permeability.

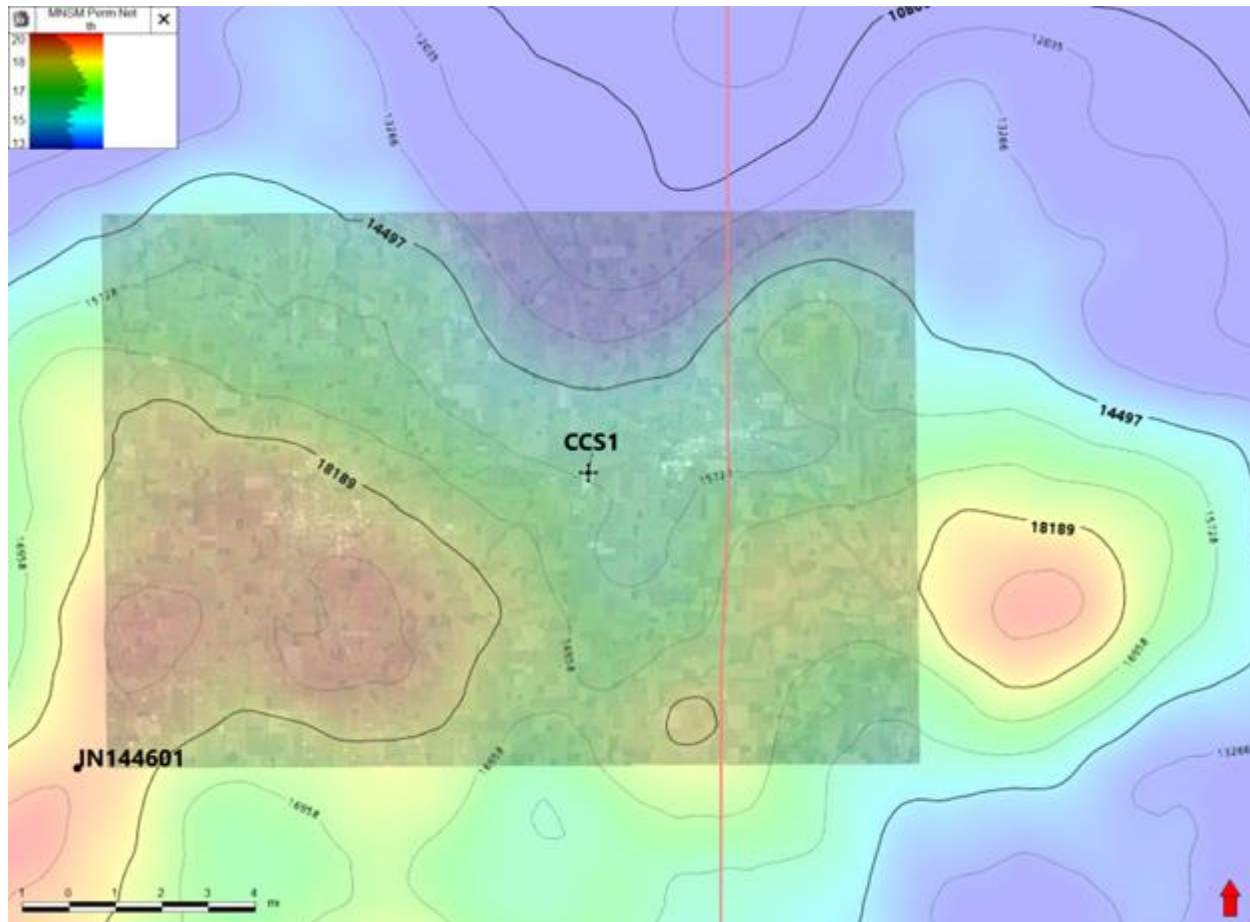


Figure 11: Permeability\*thickness (kh) Map of the Mt Simon Sandstone.

### 1.4.3 Geostatistical Summary

Geological property modelling is a complex process with many variables to optimize for each zone including variograms, co-kriging variables, data transformations, etc. A quality model should be statistically representative of the available well data and be geologically realistic. Statistical analyses were used throughout the static modeling in order to quickly identify potential errors and correct them.

Histogram displays from the model were generated for the AoR as part of the model quality control. Figure 12 shows the effective porosity and permeability histograms for the Eau Claire Shale, Eau Claire Silt, and Mt. Simon Sandstone for the AoR. Figure 13 displays the histograms of well log data, upscaled data (blocked wells) and the final property model to demonstrate how the facies properties were honored in the transition from the original well log data to the static model. Table 6 is a high-level summary of the geological characteristics of the static model.

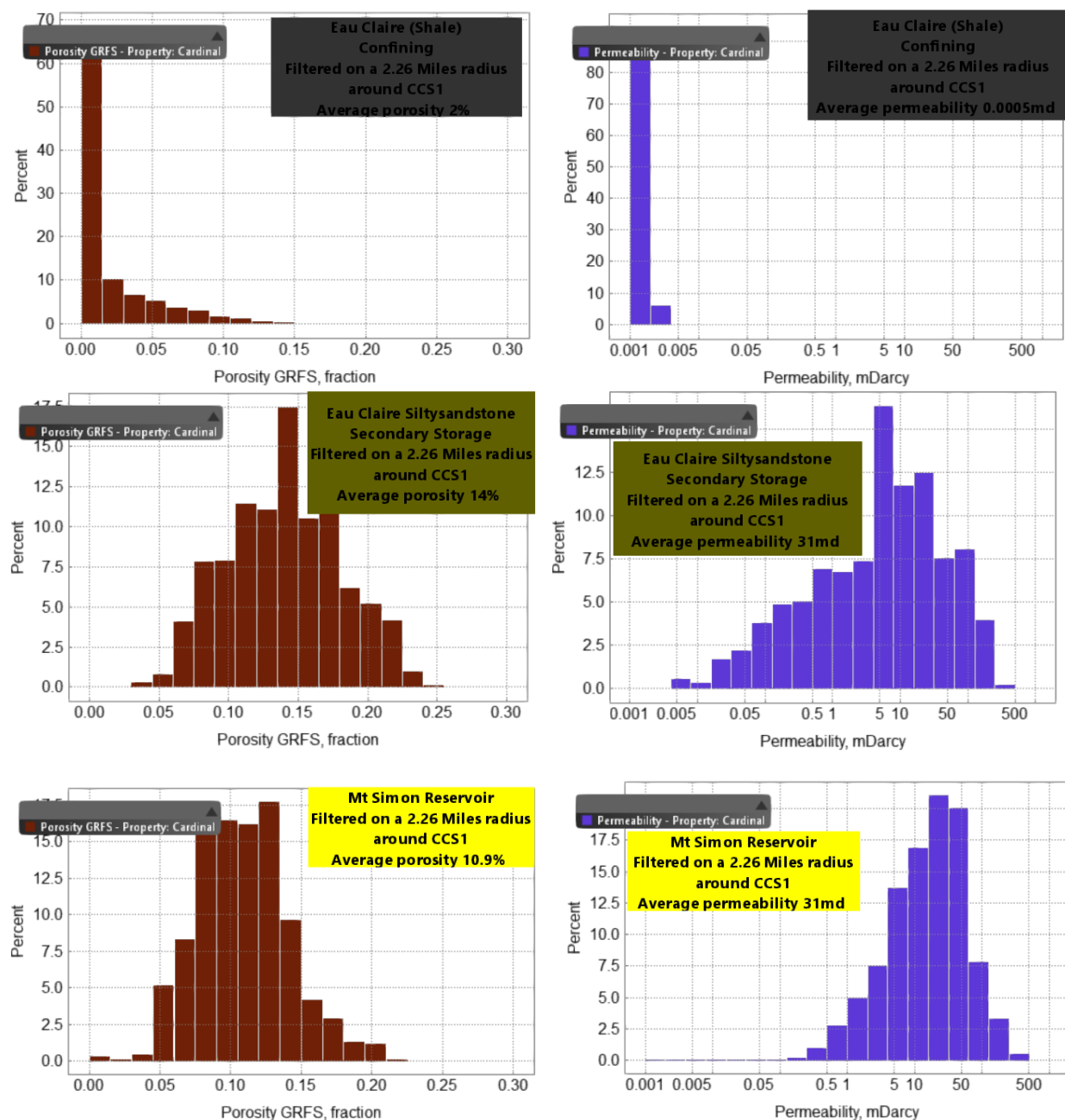


Figure 12: Effective porosity and permeability histograms for the 2.26-mile radius AoR around CCS1.

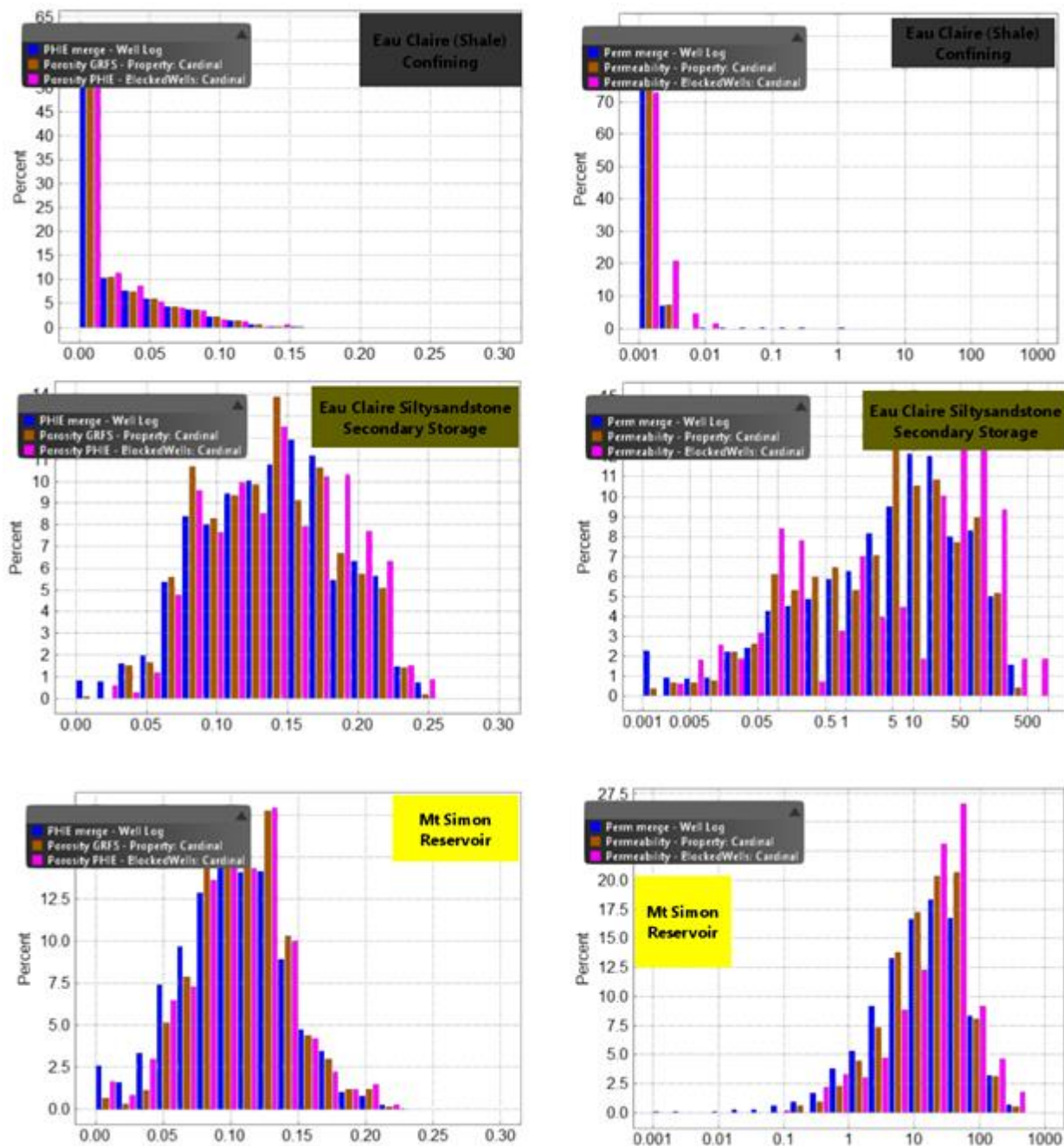


Figure 13: Effective porosity and permeability histograms of the well logs, upscaled logs (blocked wells) and the final interpolated property.

**Table 6: Summary of static model within the AoR.**

<b>Formation</b>	<b>Facies</b>	<b>Average Porosity</b>	<b>Average Permeability</b>	<b>KH</b>	<b>Thickness (ft)</b>	<b>Elevation (fbsl)</b>	<b>Depth Below Ground TVD (ft)</b>
Eau Claire Shale (confining zone)	Shale	2%	0.0005 md	<100	493-553	1,490-1,530	2,578-2,622
Eau Claire Silt (secondary sequestration)	Silty Sandstone	14%	22.6 md	840	~60	1,927-2,021	3,026-3,731
Mt Simon Sandstone (injection zone)	Sandstone_1 Sandstone_2	10.9%	31 md	11,000-18,200	456-562	1,987-2,081	3,086-3,791
Precambrian	Precambrian	uncertain	uncertain	-	basement	2,492-2,609	3,592-3,715

At present, the static model is a reliable representation of the subsurface given the current input data; however, uncertainty will exist until site specific data is acquired through the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022). Site specific well log, core, well testing data, and 3D surface seismic data are collected during the pre-operational phase of the project. Once new data has been acquired and evaluated, the static model will be updated, and the accuracy will improve.

Wireline well logs from CCS1 and the deep observation well (OBS1) will be used to calibrate 3D surface seismic data and produce inversion products such as porosity and lithology cubes for the area of the surface seismic survey. The logs can also be used to generate a discrete facies log. The facies log can be combined with the lithology cube from the surface seismic data to provide more detail on the local depositional system. The updated static model will be used for a new update to the computational modeling as discussed in Section 4.5.

The conclusions of the geologic, petrophysical, and statistical analyses include:

- The Eau Claire Formation is a thick low permeability confining zone.
- The Mt Simon Sandstone's thickness and petrophysical properties make it a reliable injection zone.
- The Eau Claire Silt is a potential secondary sequestration zone.

## 1.5 Constitutive Relationships and Other Rock Properties

A generalized gas-liquid relative permeability curve was used in the model (Figure 14). Laboratory curves are not currently available, but the curves used are consistent with published curves in the literature and include gas relative permeability hysteresis that is an important gas trapping mechanism. Calculation of the imbibition gas relative permeability curve is described below, from the GEM user's manual:

“For a non-wetting phase (gas) consider a typical drainage process (increasing gas saturation) reaching a maximum gas saturation,  $S_{gh}$ , followed by an imbibition process (decreasing gas saturation) leading to a trapped gas saturation,  $S_{grh}$ .”

The gas relative permeability on the drainage to imbibition scanning curve for a given value of the gas saturation,  $S_g$ , is given by:

$$k_{rg}(S_g) = k_{rg}^{drn}(S_{gf}) \quad (1)$$

where the free gas saturation  $S_{gf}$  is calculated from the following relationship:

$$S_{gf} = S_{gcrit} + \frac{(S_g - S_{grh})(S_{gh} - S_{gcrit})}{(S_{gh} - S_{grh})} \quad (2)$$

( $S_{gh}$  is the reversal saturation)

Capillary pressure laboratory data is not currently available but is thought to be relatively insignificant for a gas-water system in a highly permeable zone.

The rock compressibility values used in the model were derived by from nearby carbon capture and sequestration (CCS) projects. Site specific rock compressibility values will be obtained when the wells are drilled for the project as per the Pre-operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022).

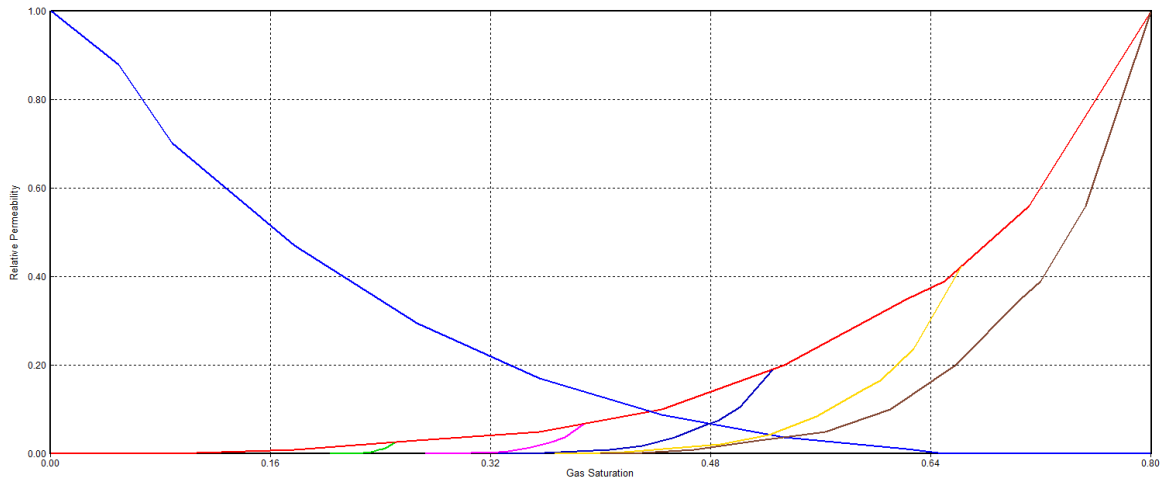


Figure 14: Gas-liquid relative permeability curves used in model, including hysteresis.

## 1.6 Boundary Conditions

In the computational model, an aquifer function (Carter-Tracy) was applied to the grid boundary (side). The top and bottom of the grid are considered no-flow boundaries. The formation was allowed to “leak”, i.e., accept fluids from the grid. This approach was used to simulate the pressure response of an infinite-acting aquifer and is considered preferable to using large pore volumes on edge grid blocks.

### 1.6.1 Initial Conditions

Initial conditions for the model are given in Table 7. The parameters were estimated from the INEOS (BP Lima) Underground Injection Control (UIC) Class I wells (Figure 1).

Table 7: Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	96	°F	2,008	INEOS (BP Lima) UIC
Formation pressure	1,183	psia	2,008	INEOS (BP Lima) UIC
Fluid density	0.465	psi/ft	2,008	INEOS (BP Lima) UIC
Salinity	120,000	TDS	2,008	INEOS (BP Lima) UIC

### 1.6.2 Operational Information

The proposed injection well, CCS1, is part of the Hoosier #1 Project. Details of the proposed injection operations are presented in Table 8.

**Table 8: Operating details.**

Operating Information	Injection Well
Location (global coordinates) Latitude 40.186587° Longitude-84.864284°	CCS1
Model coordinates (ft) X: 552167 Y: 1799966	CCS1
No. of perforated intervals	1
Perforated interval (feet below sea level (fbsl)) Z top Z bottom	2,058 2,559
Wellbore diameter (in.)	8.5
Planned injection period Start End	Q2 2024 Q2 2056
Injection duration (years)	30
Injection rate (t/day)	1,232

### 1.6.3 Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 9. Fracture gradient was estimated from mini-fracs and step-rate tests performed for:

- INEOS (BP Lima) Nitriles USA LLC UIC Class I Application (INEOS (BP Lima) Nitriles, August 22, 2016),
- Cleveland-Cliffs Steel Corporation Well # 1, (AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021),
- Vickery Well Corporation Well # 4 (Vickery Environmental, 2021).

For each of these permit applications, the Mt Simon Sandstone was tested. The project plans to perform a step-rate test in the Mt. Simon Sandstone to determine the fracture gradient at the project site as part of the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing

Program, 2022). The project specific fracture gradient will be updated in the computational model once it is available.

**Table 9: Injection pressure details**

<b>Injection Pressure Details</b>	<b>CCS1</b>
Fracture gradient (psi/ft)	0.84
Maximum injection pressure gradient (90% of fracture pressure) (psi/ft)	0.75
Elevation (ft mean sea level (MSL))	-1,100
Elevation at the top of the perforated interval (ft MSL)	2,058
Calculated maximum injection pressure at the top of the perforated interval (psi)	2,369

## **2 Computational Modeling Results**

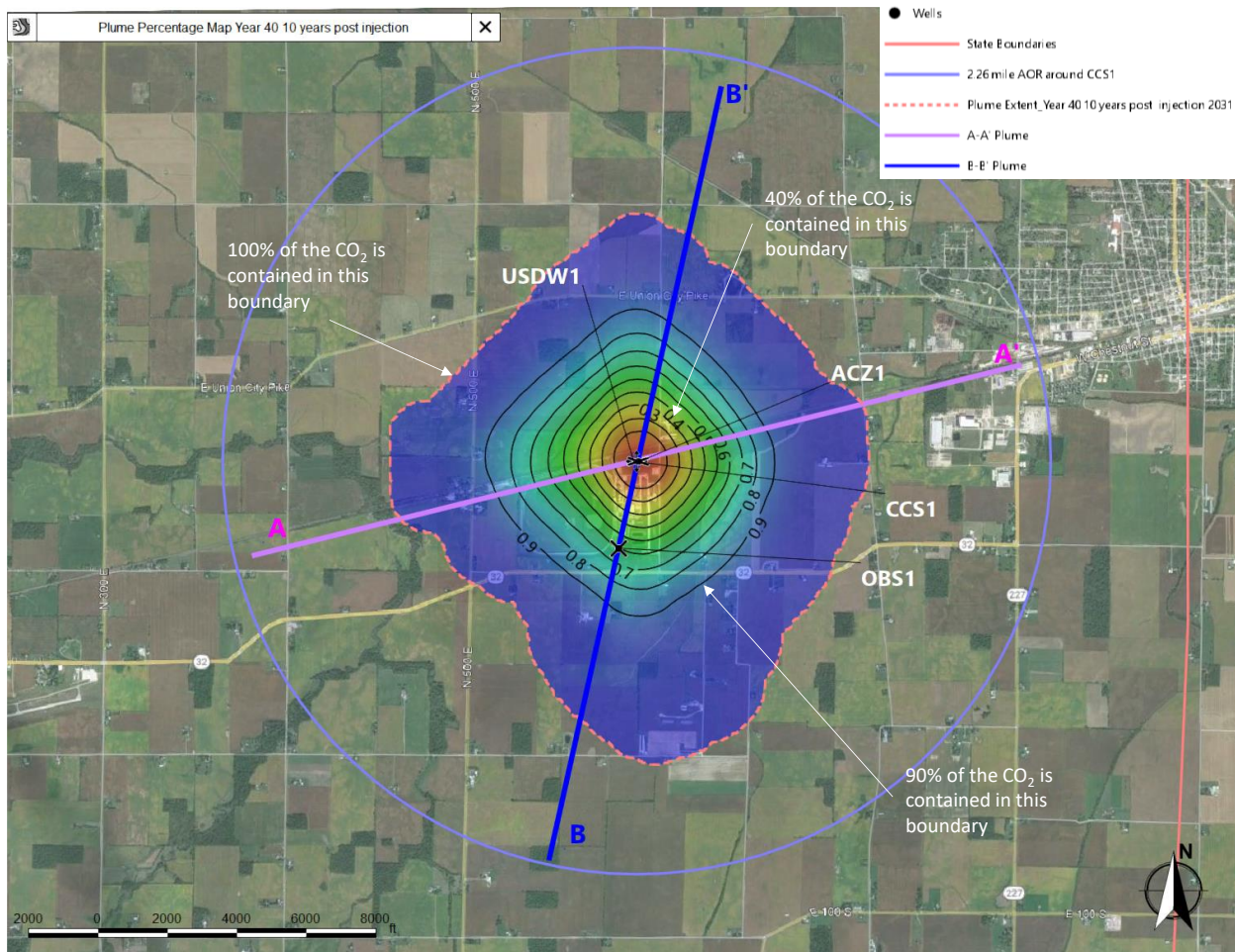
### **2.1 Predictions of System Behavior**

The following figures have been created to display the predicted behavior of the CO<sub>2</sub> plume.

- Figure 15 CO<sub>2</sub> plume with contours that indicate the percentage of CO<sub>2</sub> contained 10-years post injection.
- Figure 16 and Figure 17 display the CO<sub>2</sub> plume in cross section view.
- Figure 18 shows the predicted CO<sub>2</sub> plume at 3-, 12-, 20-, and 30-years after the start of injection and 10- and 50-years post injection.
- Figure 19 and Figure 20 show the CO<sub>2</sub> plume extent in cross section views.
- Figure 21 show three-dimensional (3D) views of the plume.

The CO<sub>2</sub> plume radius after 30-years of injection is predicted to be 1.646 miles and after 50-years post injection the radius is predicted to be 1.700 miles. Figure 18 demonstrates how quickly the CO<sub>2</sub> plume stabilizes after injection operations cease.

The pressure plume radius after 30-years of injection is 1.690 miles as shown in Figure 22. The pressure plume retracts rapidly post injection and is negligible after two years (Figure 23). The CO<sub>2</sub> and pressure plumes are irregular in shape due to the heterogeneity and dip of the formation.



**Figure 15: CO<sub>2</sub> plume with contours that indicate the percentage of CO<sub>2</sub> contained 10 years post injection. The AoR boundary is outlined in blue.**

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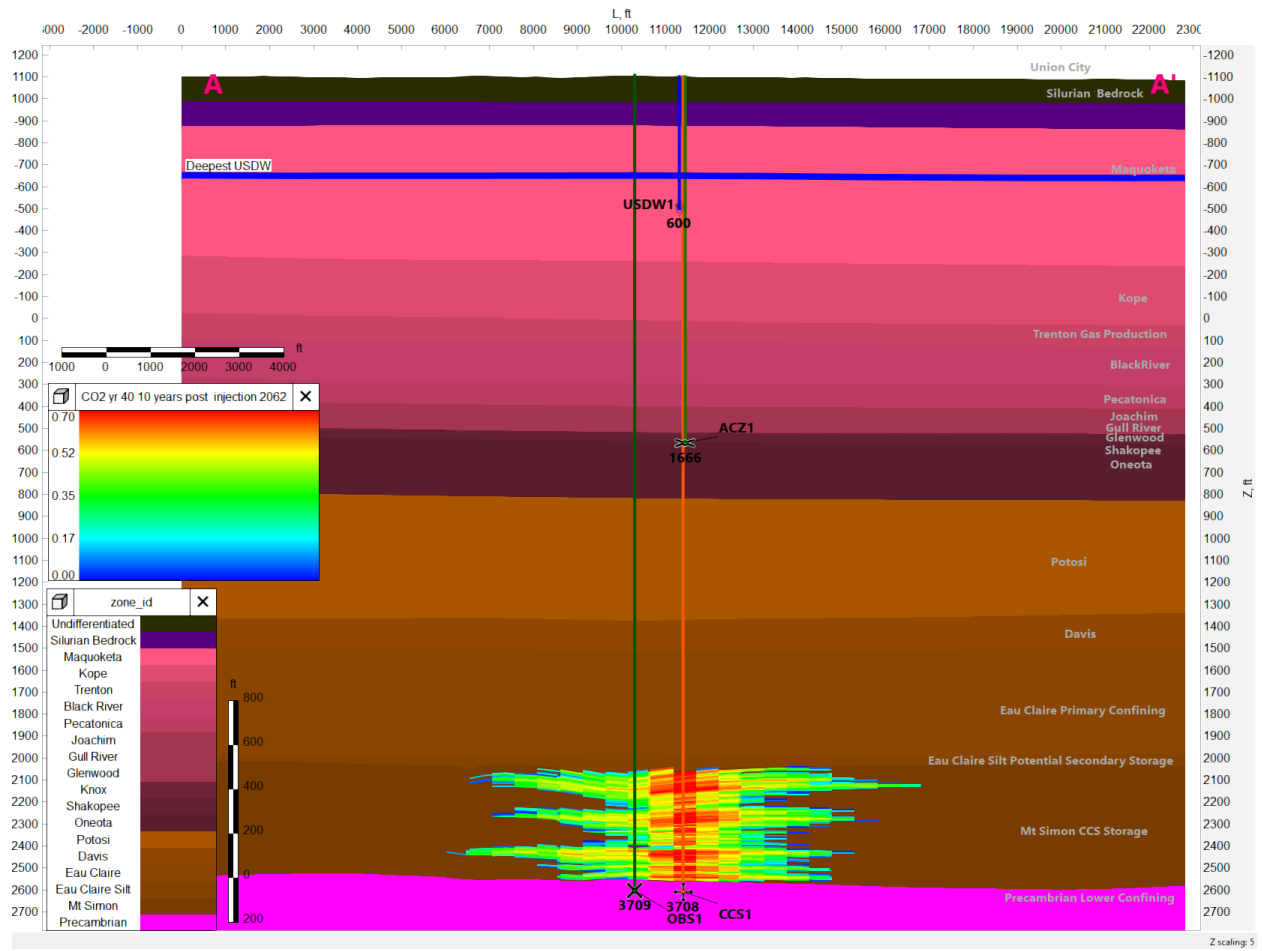


Figure 16: Cross section A-A' with the predicted 10-year post injection CO<sub>2</sub> plume.

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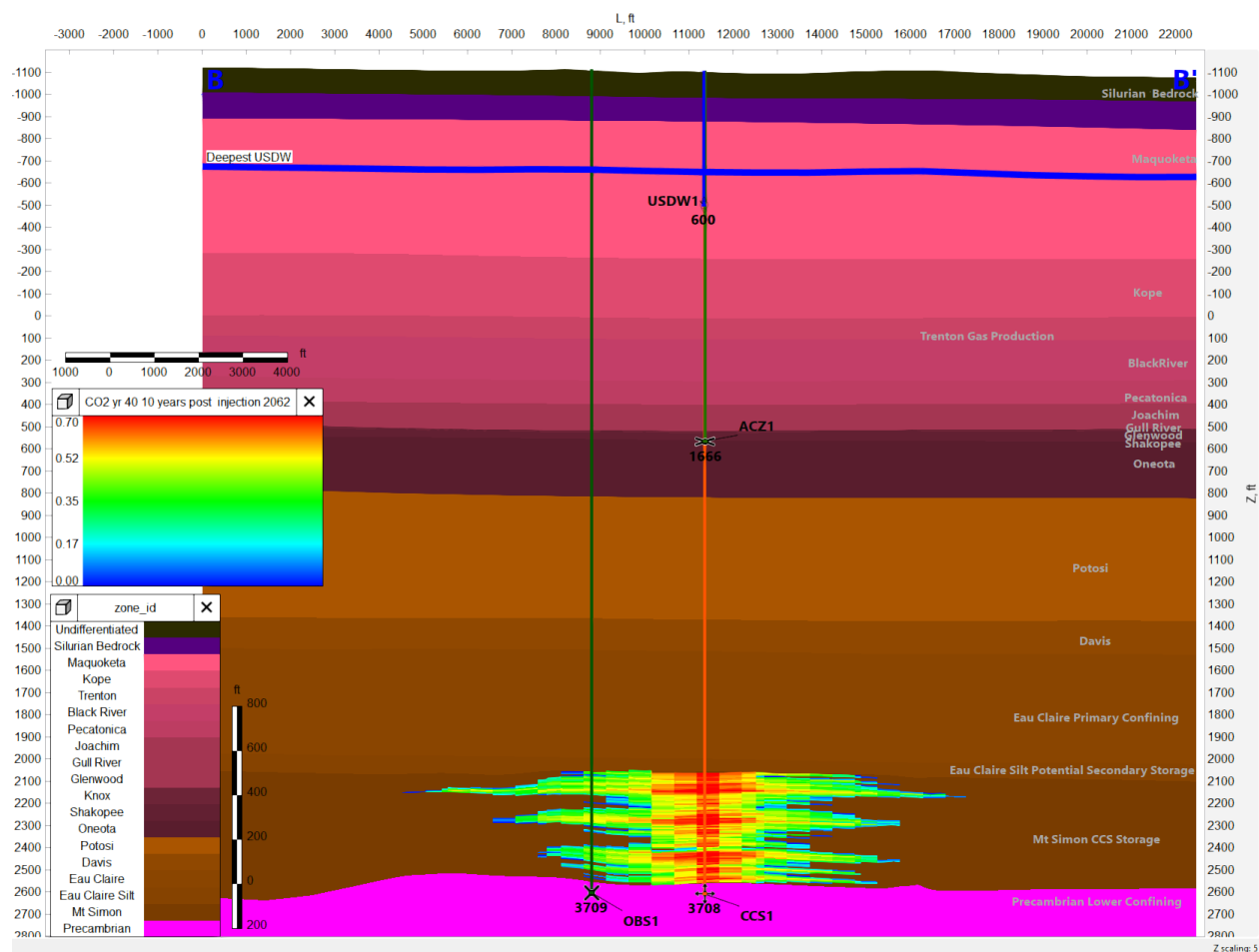
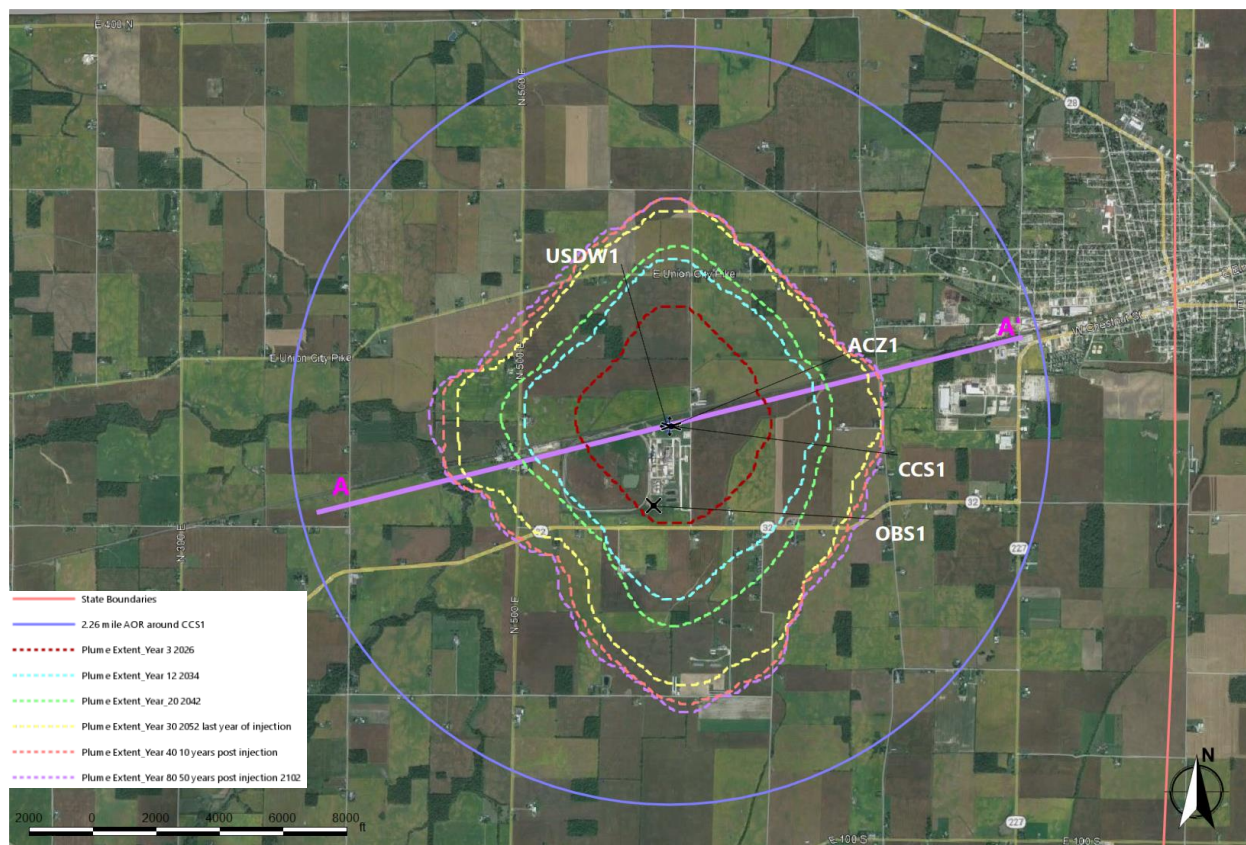
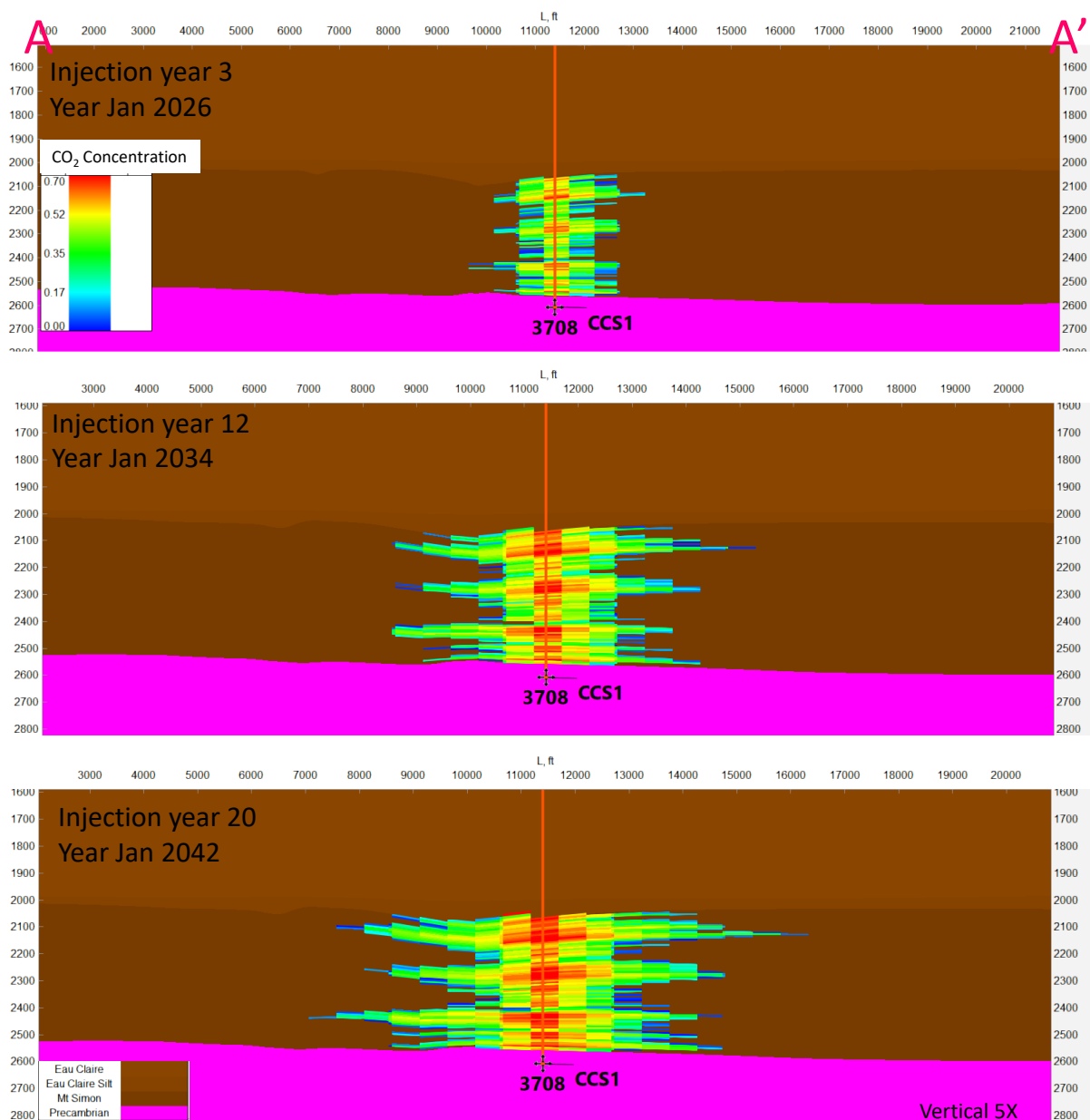


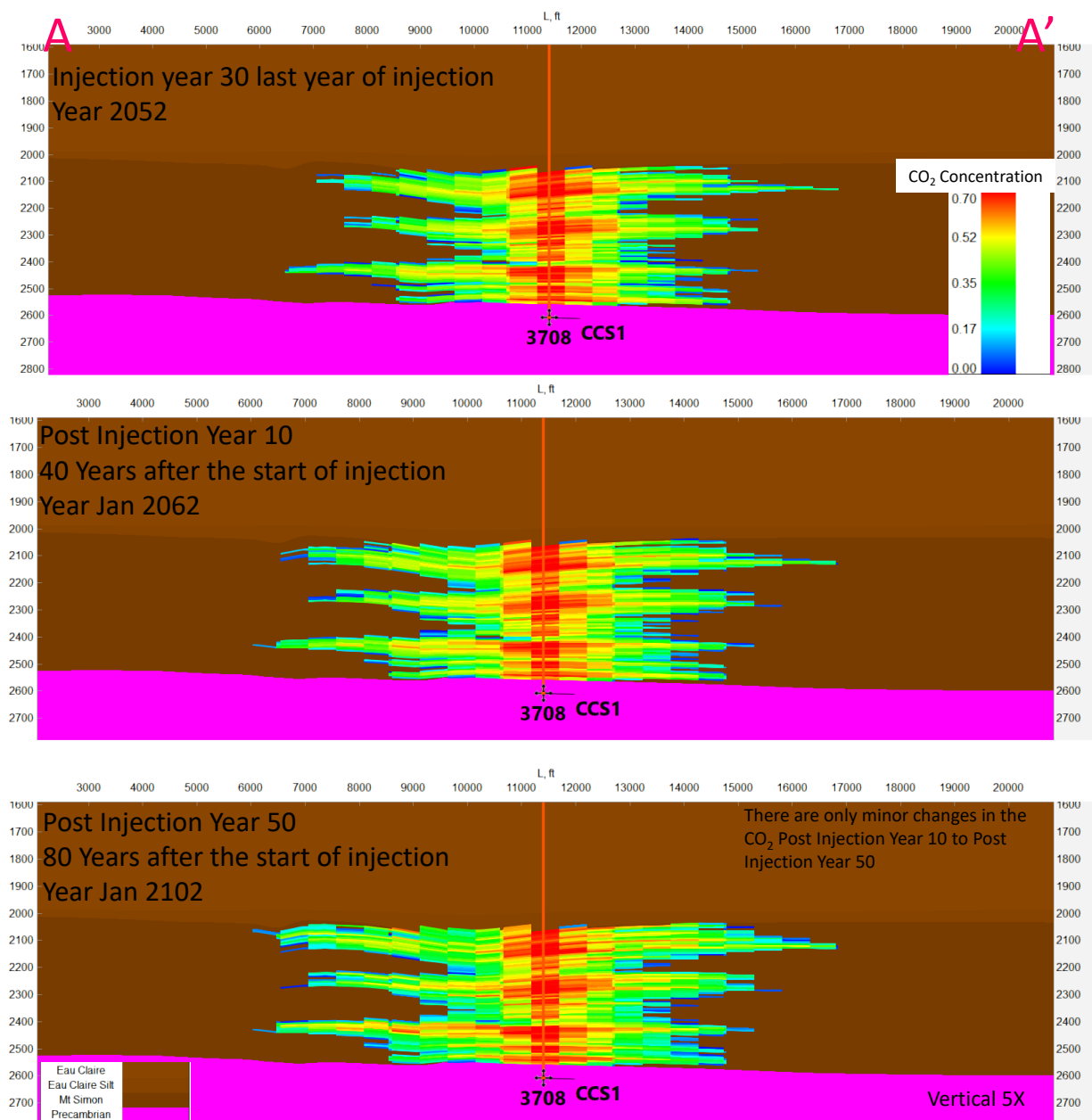
Figure 17: Cross Section B-B' with the predicted 10-year post injection CO<sub>2</sub> plume.



**Figure 18: Time-lapse CO<sub>2</sub> plume development map over 3-, 12-, 20-, and 30-years of injection as well as 10- and 50-years post injection. Note the relative stability of the CO<sub>2</sub> plume radius after injection operations cease.**



**Figure 19: Time-lapse CO<sub>2</sub> plume development cross-section A-A' at years 3-, 12-, and 20-years.**  
**Note how the heterogeneity of the injection zone affects the plume radius.**



**Figure 20: Time-lapse CO<sub>2</sub> plume development cross-section A-A' at the end of 30-years of injection and 10- and 50-years post injection.**

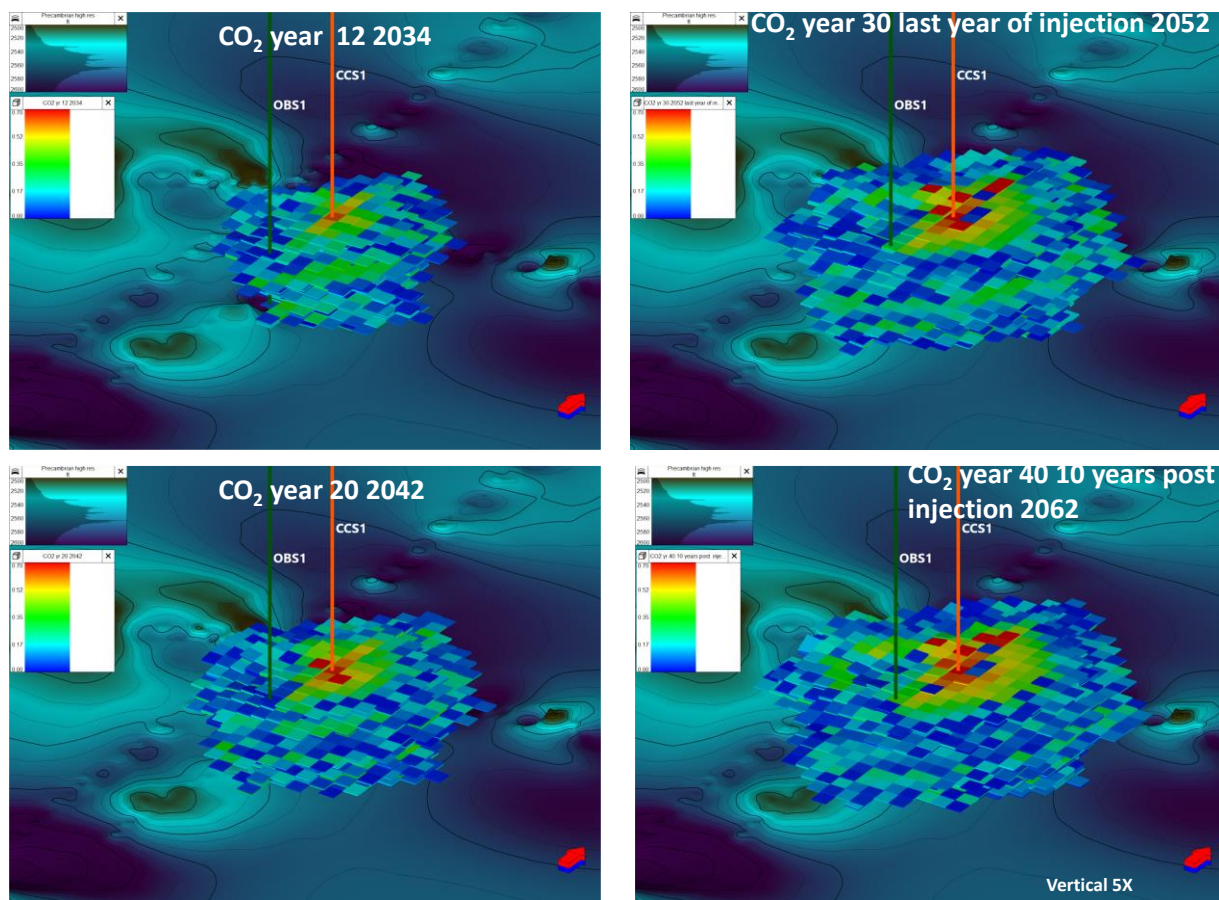


Figure 21: Time-lapse CO<sub>2</sub> plume development in 3D space.



**Figure 22: Pressure plume based on a 227 psi delta pressure and the AoR.**

The AoR was determined based on the maximum predicted pressure plume radius in addition to a 0.5 mi buffer (Section 3.2). If subsequent testing and monitoring data acquired over the operational phase of the project suggest that a larger CO<sub>2</sub> or pressure plume are likely to form, the AoR will be adjusted accordingly.

Key uncertainties include:

- Storativity (porosity x height)
- Injectivity or flow capacity (permeability x height)
- kv/kh ratio (vertical permeability divided by horizontal permeability)

When the first well is drilled for the project data will be gathered as part of the Pre-operational Testing Program to refine these parameters, and the model updated (Attachment 5: Pre-Op Testing Program, 2022). Significant changes in the AoR are not expected. The AoR was designed to account for the slight expansion of the CO<sub>2</sub> plume post injection or the maximum extent of the pressure plume (whichever is greater) and a 0.5-mile buffer. The pressure plume is expected to shrink rapidly post injection (Figure 23). The model will be refined and updated with injection well data and data from observation well.

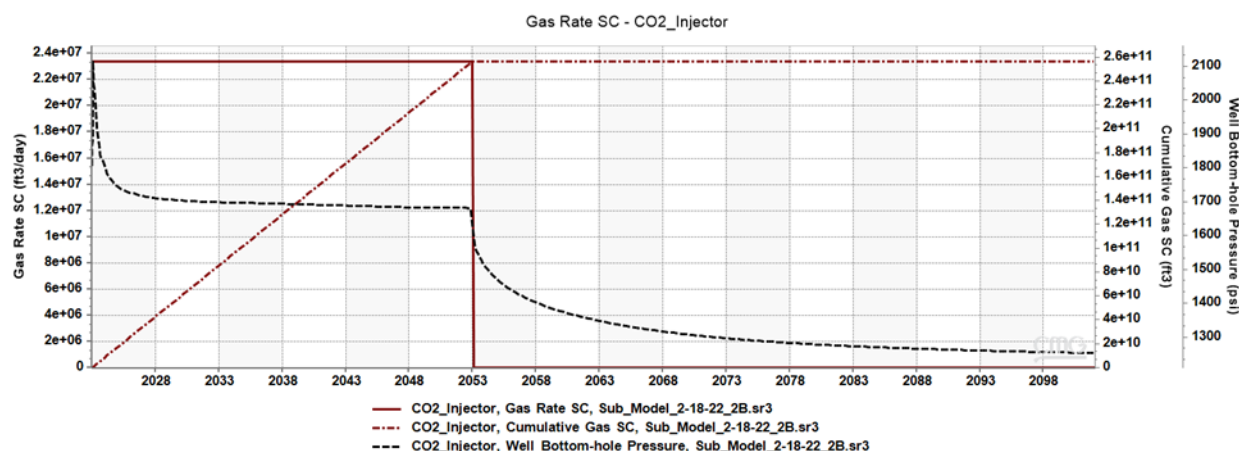


Figure 23: Predicted fall-off in bottomhole pressures (BHP) once injection operations cease after 30 years.

Figure 24 shows a breakdown of the mass of the CO<sub>2</sub> injected into three phases: supercritical fluid, dissolved gas, and trapped gas. After 50-years post-injection, the percentage breakdown are: 61%, 17%, and 22%, respectively. The percentages of dissolved gas and trapped gas will continue to increase over time while the supercritical gas will decrease. Mineralization takes place over a much longer time and has not been included in Figure 24.

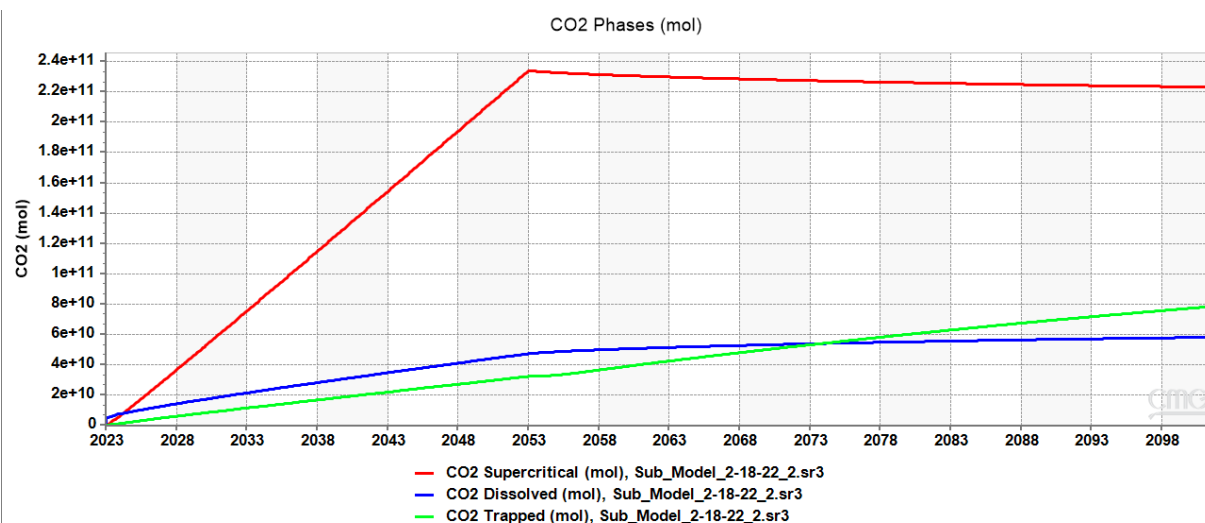


Figure 24: Chart showing supercritical gas, dissolved gas, and trapped gas over time.  
(Mineralization is not significant during this time frame.)

## 2.2 Model Calibration and Validation

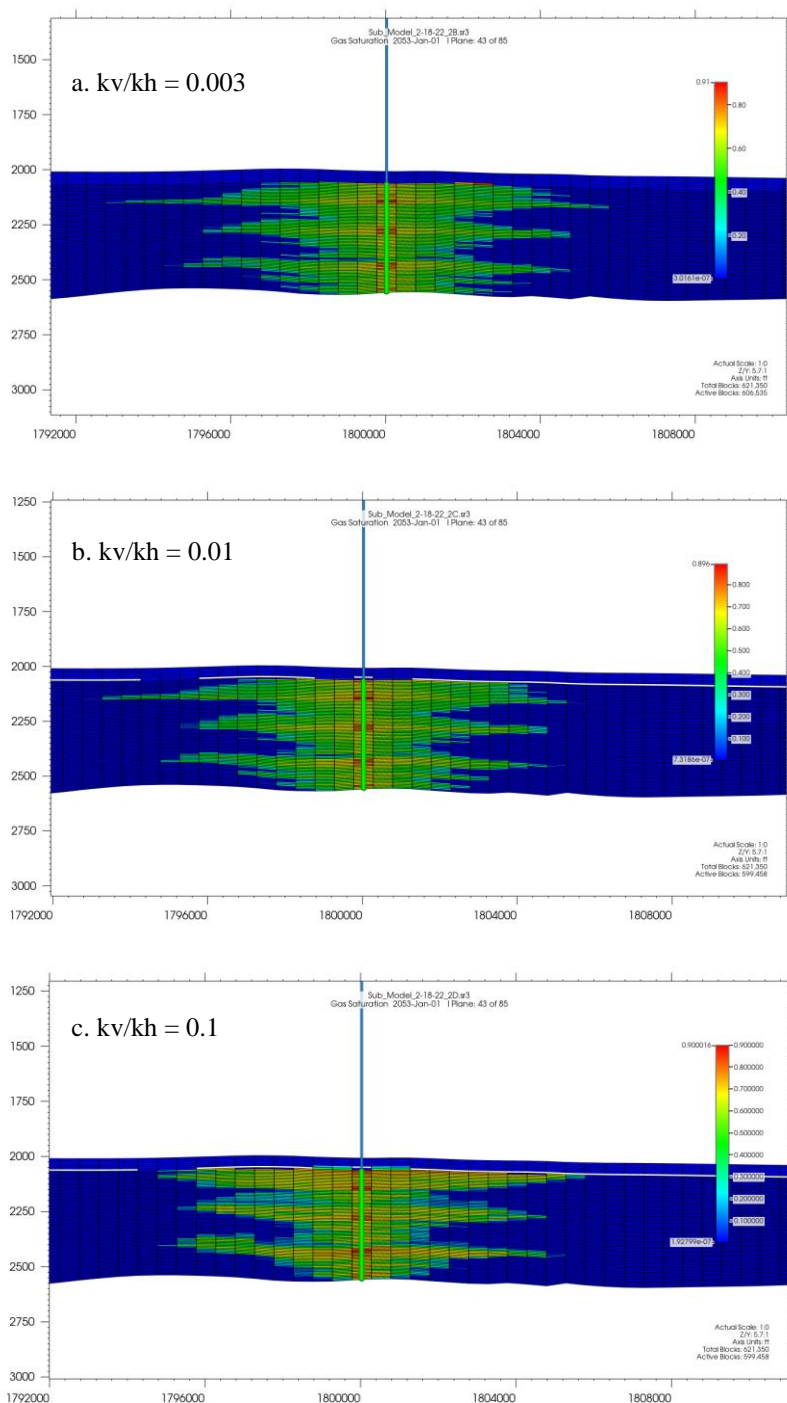
History matching was not performed as there is no current injection data available. The model was constructed using all available reference information from the INEOS (BP Lima), A.K. Steel, and Vickery UIC projects, which included computational modeling studies (INEOS (BP Lima) Nitriles, August 22, 2016; AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021; Vickery Environmental, 2021).

The kv/kh ratio is a significant unknown given the lack of deep well data in the region. Sensitivity analysis was conducted to evaluate the effect of kv/kh ratio on the CO<sub>2</sub> plume size. The kv/kh value used in the base case is 0.003, which was estimated from a fall-off test from the INEOS (BP Lima) Project. Sensitivity cases were run with kv/kh values equal to 0.01 and 0.1. The individual simulations indicated that the CO<sub>2</sub> plume would be smaller with increasing values of kv/kh. As kv/kh values increase the rate of vertical migration of the CO<sub>2</sub> is higher resulting in more residual gas trapping. Lower values of kv/kh result in greater horizontal migration of the CO<sub>2</sub> and a larger CO<sub>2</sub> plume. Table 10 and Figure 26 demonstrate the effect of kv/kh on relative size of the CO<sub>2</sub> plume.

**Table 10: Impact of varying kv/kh values on the CO<sub>2</sub> plume radius.**

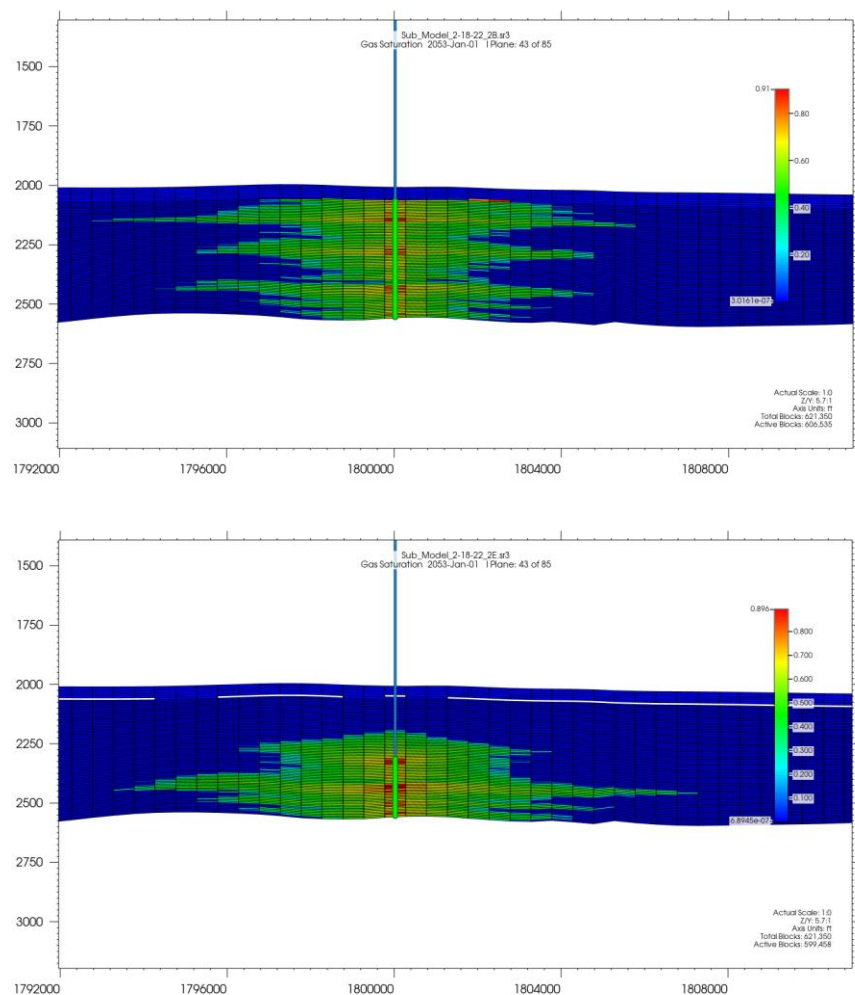
<b>kv/kh</b>	<b>CO<sub>2</sub> Plume Radius (mi)</b>
0.003	1.32
0.01	1.23
0.1	1.02

The effect of partial completion was also studied as a sensitivity. The modeling demonstrated that the entire interval would need to be perforated to sustainably achieve the required rate from the start of injection. A partial completion could result in higher rates of vertical gas migration which would result in higher rates of gas trapping and a smaller CO<sub>2</sub> plume. However, in this case, the difference in plume size was negligible (Figure 26).



**Figure 25: Effect of kv/kh ratio on CO<sub>2</sub> plume size. Increasing kv/kh results in smaller CO<sub>2</sub> plume size because of higher rates of residual gas trapping. a. kv/kh = 0.003, b. kv/kh = 0.01, c. kv/kh = 0.1.**

Plan revision number: N/A  
Plan revision date: July 4, 2022



**Figure 26: Effect of partial completion on CO<sub>2</sub> plume size. Although full completion is necessary to achieve the required injection rate, no difference in maximum radius over time was observed.**

### 3 AoR Delineation

#### 3.1 Critical Pressure Calculations

To delineate the pressure plume radius, a minimum (or critical) delta pressure was calculated. The delta pressure is the increase in pressure necessary to overcome the hydrostatic head of the injection zone fluid and would allow fluids to migrate up an open conduit to the lowermost USDW in the unlikely event that a conduit exists. The formula for calculating the delta pressure is given below (source: UIC Program Class VI Well Area of Review and Corrective Action Evaluation Guidance)

$$\Delta P_{if} = P_u + \rho_i * (z_u - z_i) - P \quad (3)$$

Where:

$\Delta P_{if}$  = delta pressure,

$P_u$  = initial pressure of the lowermost USDW,

$\rho_i$  = fluid density of the injection zone,

$g$  = acceleration due to gravity,

$z_u$  = elevation of the lowermost USDW,

$z_i$  = elevation of the injection zone, and

$P$  = initial pressure of the injection zone. Substituting appropriate values into the equation, a minimum delta pressure was calculated to be 227 psi.

#### 3.2 AoR Delineation

The AoR was initially selected by observing the delta pressure of each gridblock in the model after 30 years of injection. The gridblocks that had a delta pressure equal to or greater than the minimum delta pressure (calculated above) and considered to be in the AoR. A radius was measured from the wellbore location to the maximum extent of the pressure plume. A 0.5-mile buffer was added to be conservative. Through the Pre-operational Testing Program, uncertainties around the injection zone parameters will be addressed, and the static and computational models will be updated with the new data (Attachment 5: Pre-Op Testing Program, 2022). The new computational model will be used to recalculate a new maximum radius and the AoR will be revised if necessary. OBS1 will be used to monitor changes in injection zone pressure and aqueous geochemistry at a distance from the injection well (Attachment 7: Testing And Monitoring, 2022). The computational model will be updated to match the observed data. If the injection zone does not perform as predicted, the AoR will be re-assessed if necessary.

## **4 Corrective Action**

EPA Class VI regulations require the identification of all confining zone penetrations within the AoR because these wells could become a preferential pathway for leakage of CO<sub>2</sub> and/or formation brine fluids out of the injection zone. If necessary, corrective actions will need to be performed on the penetrations to prevent leakage that could potentially cause endangerment to a USDW. The following sections discuss the findings of an evaluation that was performed to:

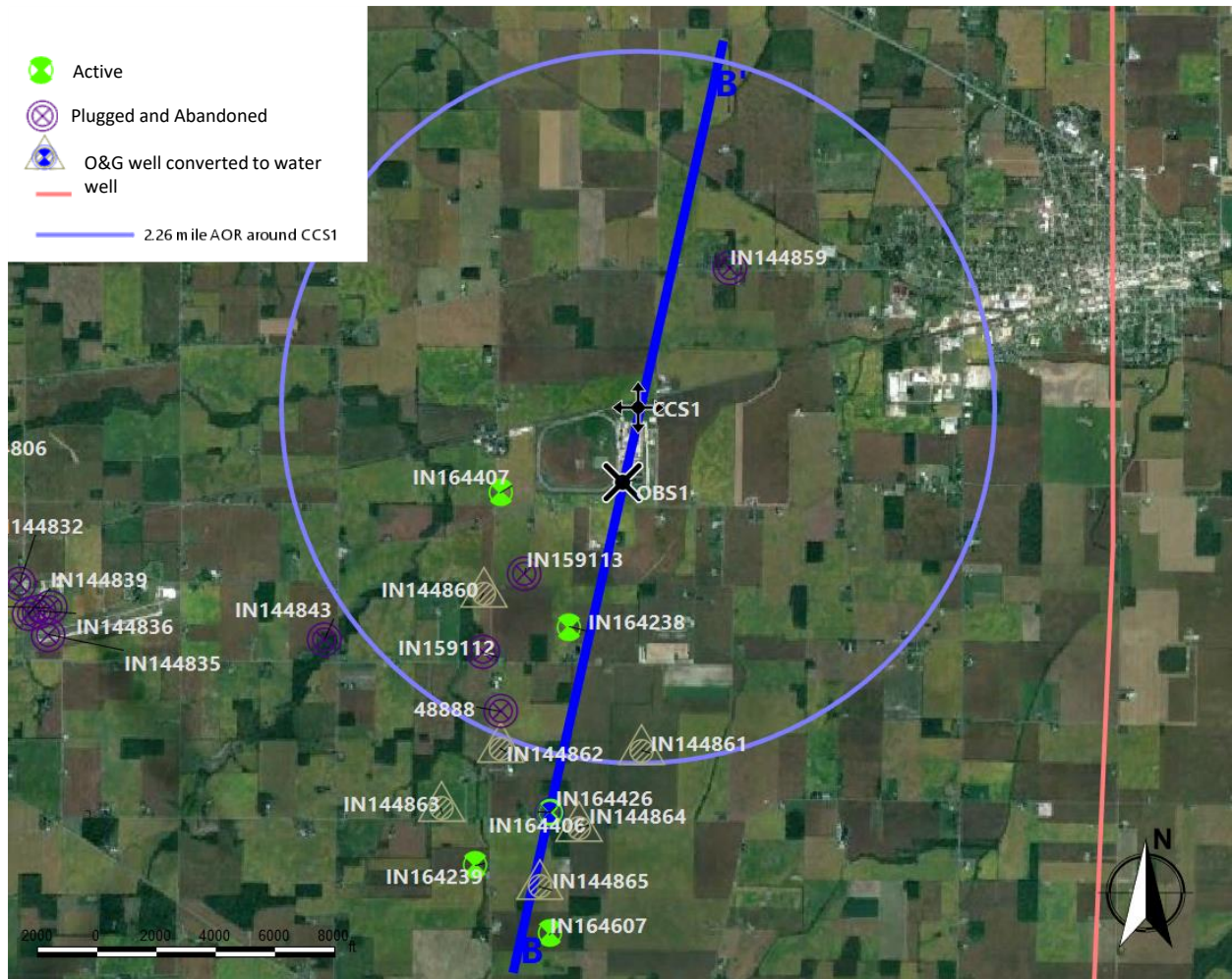
- Identify existing penetrations within the vicinity of the AoR,
- Determine if any penetrations extend below the primary confining zone, thereby presenting a risk of leakage that may require corrective actions,
- Identify corrective actions and define the approach that will be taken to prevent leakage that could endanger a USDW.

### **4.1 Tabulation of Wells within the AoR**

#### **4.1.1 Oil and Gas Wells**

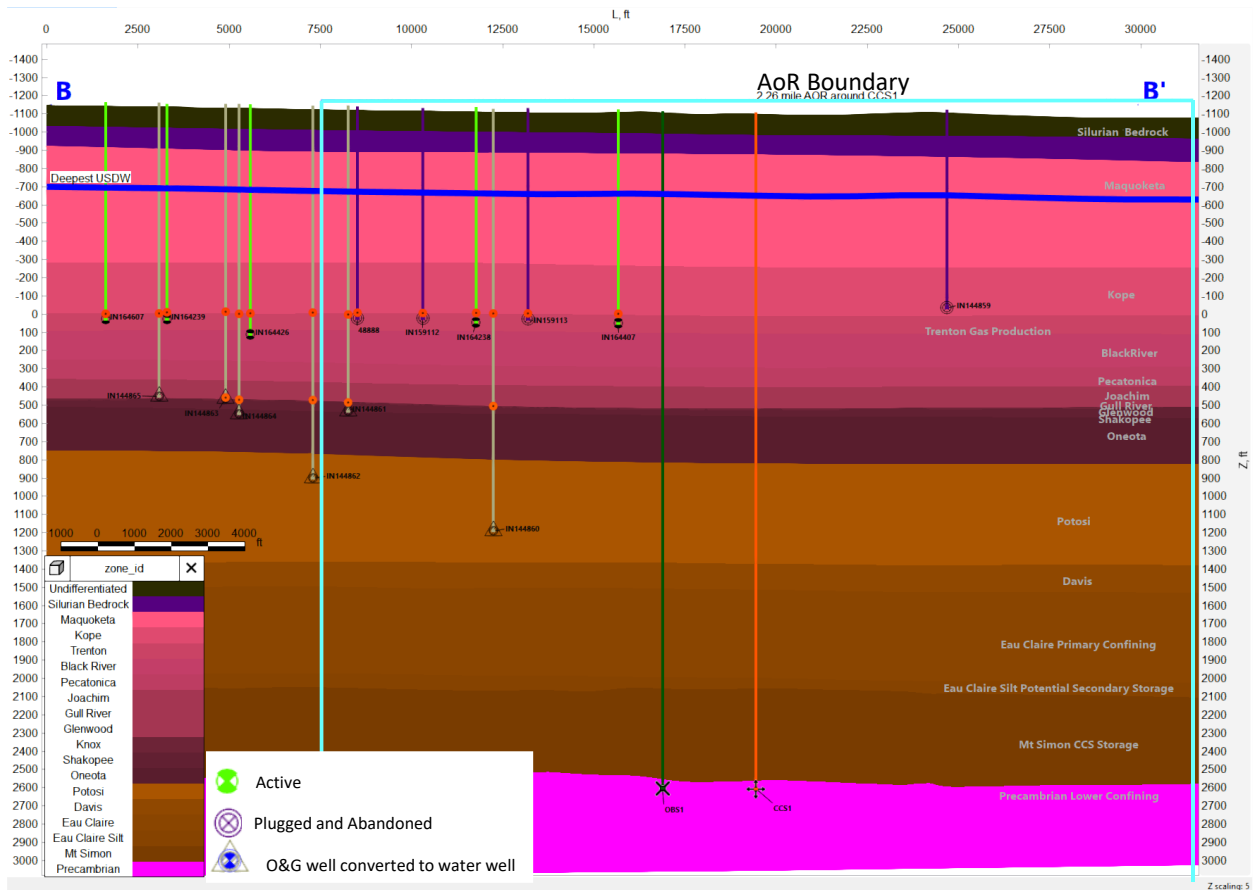
There are seven oil and gas (O&G) wells found within a 2.26-mile AoR (Figure 27, Figure 28, and Table 11); two of these wells have been converted to shallower groundwater wells. The deepest well is IN144860 (Permit# 30922). It is located approximately 1.5 miles southwest of the proposed CCS1 site and reaches a depth of 2,310 ft, which is >300 ft above the estimated top of the Eau Claire Shale. The well was drilled and completed in 1967 as a Trenton O&G well. 4.5-inch casing was set at 1,245 ft and cemented with 75 sacks of cement. The Indiana Department of Natural Resources (IDNR) has plans to plug this well in 2022.

The closest well (IN164407) is located approximately 1.0 miles west – southwest of the proposed CCS1 site. It was drilled in 2006 and is 1,166 ft deep and approximately 50 ft below Trenton top. 6.625-inch casing was set at 495 ft and cemented with 55 sacks of cement. A temporary abandonment was issued and expired on 6/8/2015.



**Figure 27: O&G wells within the AoR. There are only two active O&G wells within the AoR. The rest of the wells are either plugged and abandoned or have been converted to shallower water wells.**

Plan revision number: N/A  
Plan revision date: July 4, 2022



**Figure 28: Cross Section B-B' with O&G gas well penetrations in the AoR projected from 1 mile. None of the O&G wells penetrate the confining layer. The cyan lines denote the AoR boundaries.**

**Table 11: O&G well penetrations in the AoR. Note that only two wells penetrate the Knox Formation.**

IGSID	Permit	Distance from CCS1 (miles)	Lease	Complete Date	Plugged Date	Status (Plugged and Abandoned (P&A), Active, etc.)	Producing Formation(s)	Formation at TD	Total Depth (ft)	Comment
164407	53114	1.036	Noel Carpenter	11/22/2006	-	Active	Trenton Limestone	Trenton Lm	1166	-
144859	144859	1.041	Conklin	1913	-	Presumed Plugged	Trenton Assumed	Kope Fm	1080	-
164238	52946	1.459	Hime Farm Corp	8/9/2006	-	Active	Trenton Limestone	Trenton Lm	1174	-
144860	30922	1.526	Fred Tibbetts #1	5/17/1967	-	O&G Well converted to water well	Trenton Limestone	Potosi Fm	2310	Well permit revoked, converted to Water Well 136398, plugged plan for winter 2022
159112	48735	1.826	Tibbetts #2	12/33/1988	7/26/1989	P&A	Trenton Limestone	Trenton Lm	1148	-
48888 (IN159114)	48888	2.121	Bentz #2	12/27/1988	8/4/1989	P&A	Trenton Limestone	Trenton Lm	1156	Same well as IGSID 159114 (which is presumed to be plugged)
144861	31891	2.163	Katherine A. McCormick / Frazier #2	4/29/1969	-	O&G Well converted to water well	Trenton Limestone	Shakopee Fm	1670	Well permit revoked, converted to Water Well 272453

#### 4.1.2 Water Wells

Water wells are the most common well type within the AoR. The latest estimate shows that a total of 183 groundwater wells are located within the 2.26-mile AoR of CCS1 (Figure 29 through Figure 31). The shallow groundwater water wells have depths of less than 321 ft and average 148 ft. The wells labeled on Figure 29 were originally O&G wells that were plugged back and recompleted as water wells. Only two of these deep-water O&G wells are in the AoR, and none of these wells penetrate the Eau Claire Shale.

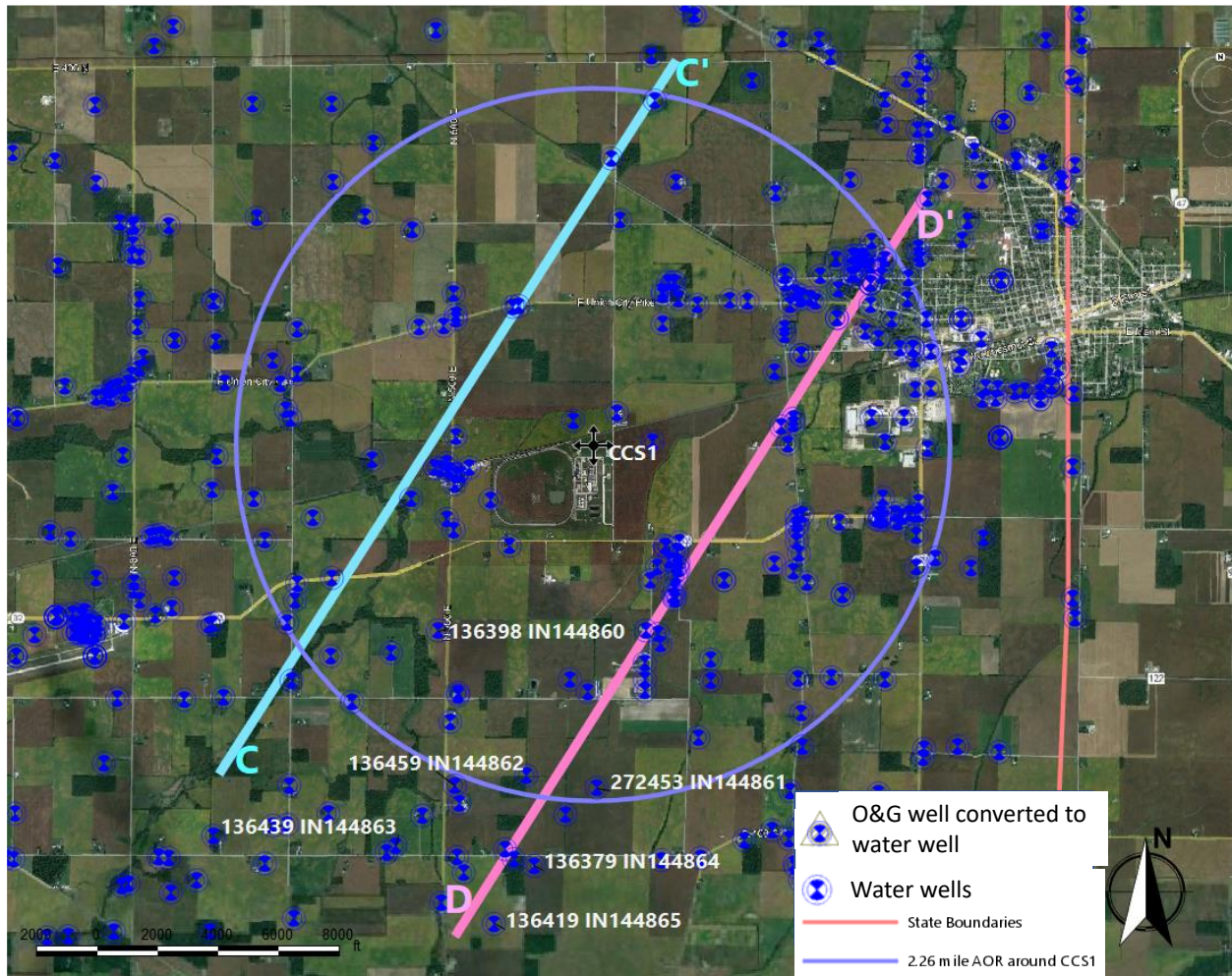
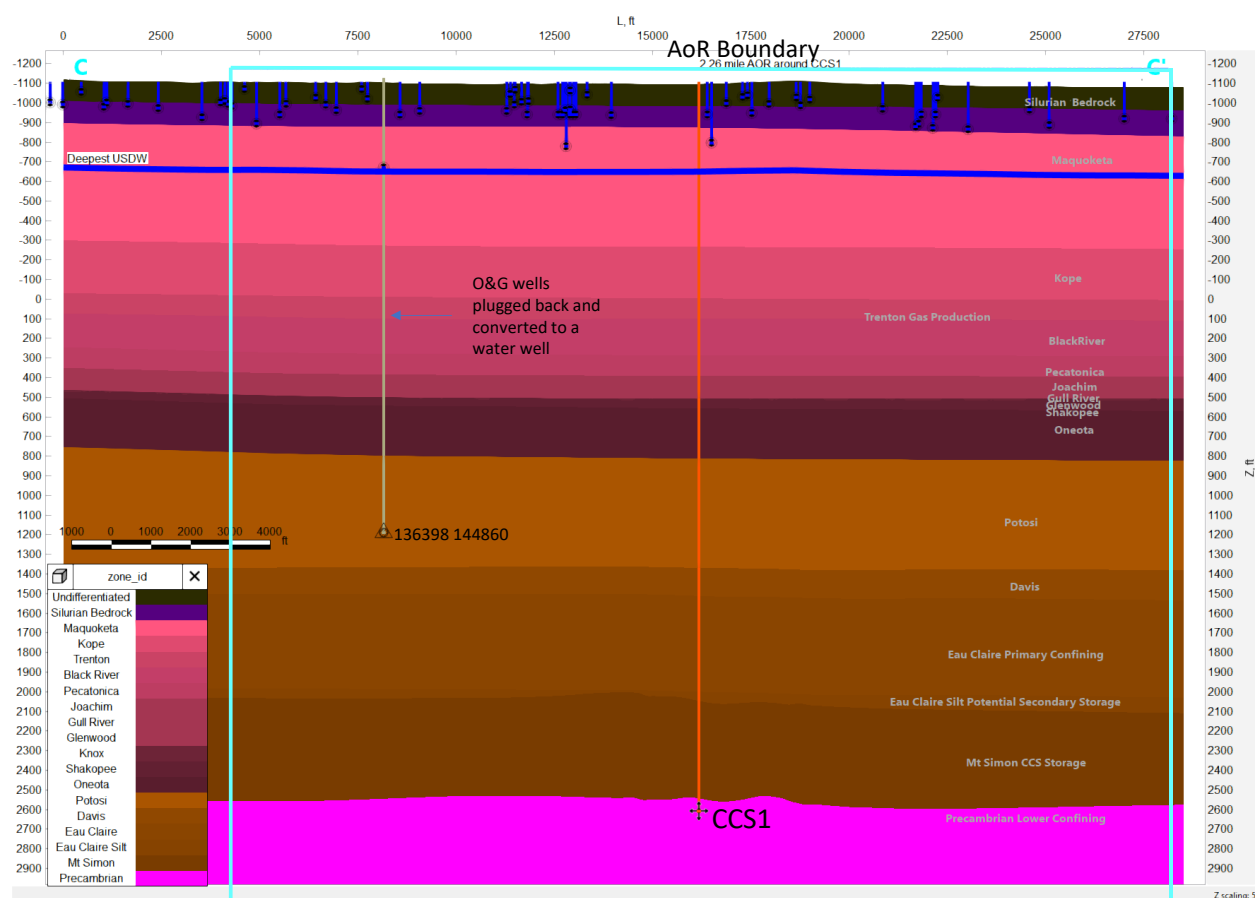
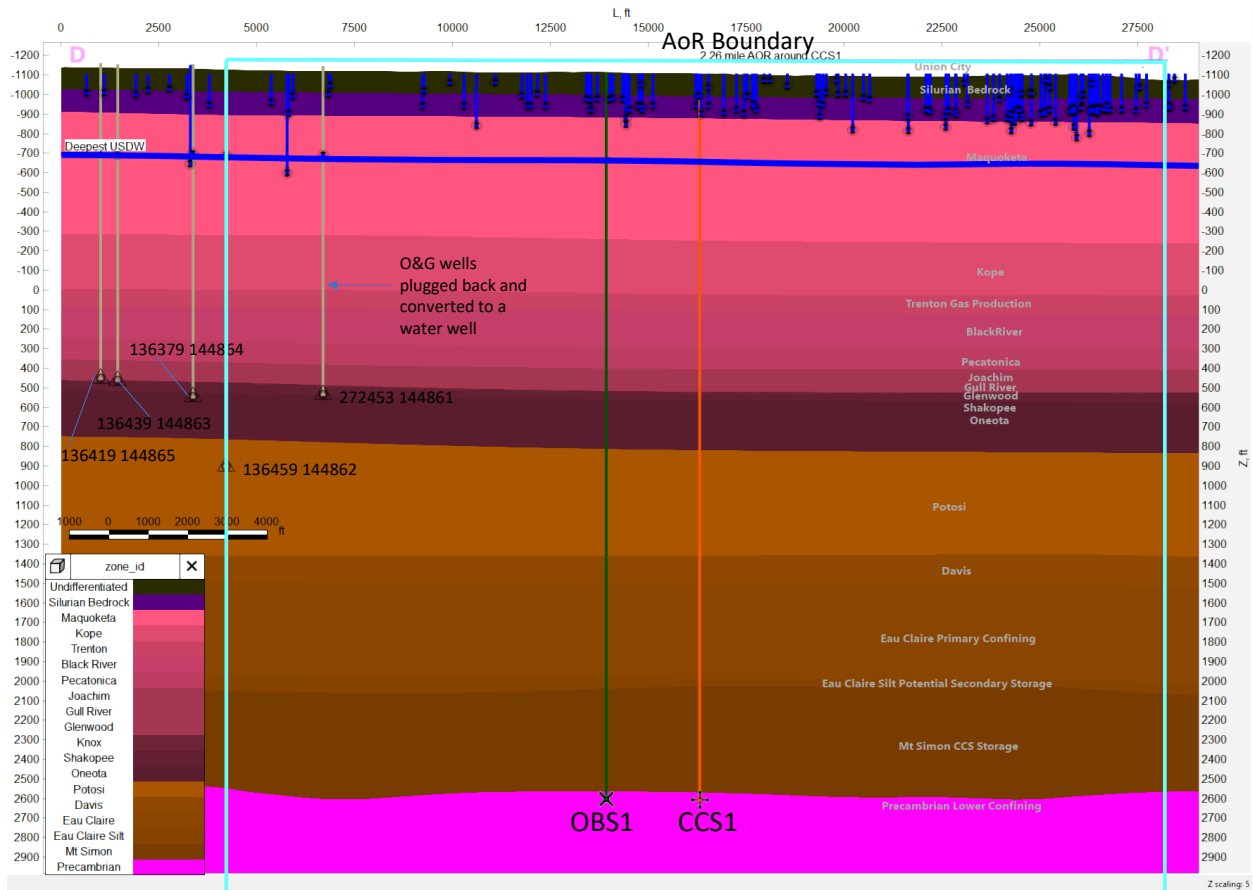


Figure 29: Groundwater wells within the AoR. O&G wells that have been converted to water wells in the area have been highlighted.

Plan revision number: N/A  
Plan revision date: July 4, 2022



**Figure 30: Cross-section C-C' displaying groundwater wells. Wells were projected from one (1) mile. Note that one water well penetrates the Potosi Formation and IDNR has plans to plug this well. The cyan lines denote the AoR boundaries.**



**Figure 31: Cross-section D-D' through groundwater wells. Wells were projected from one (1) mile. Note that one water well penetrates the Shakopee Formation within the AoR. The cyan lines denote the AoR boundaries.**

## 4.2 Wells within the AoR

Details of the O&G, and water wells have been provided in the preceding section. The Indiana Geological and Water Survey (IGWS) and IDNR, Division of O&G sites were used to compile the data for this section. The Hoosier #1 Project is located at T20N R15E Section 17, Randolph County. No deep wells were identified in this Township and Range in a special Report 51 (Table 12). Therefore, it is highly unlikely that there was historical drilling prior to the 1960's. It is not believed there are any historical wells in the area that are not captured in available data sources.

**Table 12: Special Report 51 indicates no deep wells for immediate area (Sullivan, 1995).**

		Producing Stratigraphic Unit			Number of Gas Wells				
County, Township & Range	Name <sup>†</sup>	Avg. Depth to Top (ft)	Lithology	Avg. Thickness (ft)	Shut-in	Home-use	Commercial	Abandoned	Average IP in MCFPD <sup>‡</sup>
Marion									
15N-5E	Trent	—	Dol	—	0	0	0	1	—
16N-5E	Trent	1050	Dol	—	0	0	0	4	—
17N-5E	Trent	—	Dol	—	0	1	0	13	—
Miami									
25N-5E	Trent	—	Dol	—	0	0	0	5	—
25N-6E	Trent	—	Dol	—	0	0	0	4	—
Randolph									
19N-12E	Trent	—	Dol	—	0	0	0	1	—
19N-13E <sup>†</sup>	Trent	—	Dol	—	0	1	0	0	—
19N-14E	Trent	—	Dol	—	0	3	0	21	—
19N-1W	Trent	—	Dol	—	0	0	0	1	—
20N-12E	Trent	—	Dol	—	0	0	0	6	—
20N-13E	Trent	1020	Dol	—	0	4	0	12	—
20N-14E	Trent	1040	Dol	—	0	4	0	49	—
21N-12E	Trent	930	Dol	—	1	5	0	32	—
21N-13E	Trent	940	Dol	—	0	1	0	10	—
21N-14E	Trent	1010	Dol	—	0	1	0	22	—
21N-15E	Trent	—	Dol	—	0	3	0	16	—
Ripley									
8N-10E	Trent	897	Dol	—	0	1	0	0	—
9N-11E	Trent	—	Dol	—	0	0	0	3	—

#### 4.2.1 Wells Penetrating the Confining Zone

As previously stated, the deepest well (IN144860) is located approximately 1.5 mi southwest of the proposed CCS1 locations and reached a depth of 2,310 ft, which is >300 feet above the estimated Eau Claire Shale top. No wells have penetrated the Eau Claire Shale in the AoR, and no corrective action required.

#### 4.3 Plan for Site Access

The four primary wells associated with the project (CCS1, OBS1, ACZ1, and USDW1) are located on Cardinal Ethanol property and have been sited to minimize issues with flooding or other stormwater related issues. Surface use agreements will be put in place to allow surface access for periodic 3D seismic data acquisition as well as periodic water sampling. As noted in these surface use agreements, proper notification will be given prior to accessing property to collect water samples.

#### 4.4 Corrective Action Schedule

Currently no wells within the AoR require corrective action. As such, no corrective action schedule is necessary at this time.

## **4.5 Reevaluation Schedule and Criteria**

### ***4.5.1 AoR Reevaluation Cycle***

The project will reevaluate the above described AoR every five years during the injection and post-injection phases of the project. Additionally, any significant changes to the CO<sub>2</sub> stream or an increase in the injection volumes will trigger a reevaluation of the AoR.

As part of this reevaluation, monitoring and operational data will be used to calibrate the performance of the well and injection zone to the computational modeling. In addition to reviewing the testing and monitoring data on five-year intervals, this data will also be assessed on an annual basis to monitor for any unexpected changes in behavior. The testing and monitoring data will be included in the model to help calibrate and fine tune the computation modeling (history matching). The testing and monitoring data will include of (but is not limited to) the following:

- Surface and bottomhole pressure
- Total mass injected and mass injection rates
- Mechanical integrity logs
  - Temperature logs
  - PNL
- Time-lapse 3D seismic data
- Microseismic monitoring

Should notable deviations from the computational modeling results occur, the modeling will be re-run, and a new AoR will be re-established. Notable deviations are defined in the following section.

### ***4.5.2 Triggers for AoR Re-evaluations Prior to the Next Scheduled Reevaluation***

Table 13 presents a non-exhaustive list of potential parameters that would trigger a reevaluation of the AoR prior to the next scheduled re-evaluation should notable deviations from anticipated values occur.

**Table 13: List of potential parameters that could initiate re-evaluation of the AoR. (Note that this list is non-exhaustive.)**

Monitoring Parameter	Description
Pressure	<ul style="list-style-type: none"> <li>Sustained variations in pressure outside of three standard deviations from the average</li> </ul>
Temperature	<ul style="list-style-type: none"> <li>Variations in temperature observed during MIT logging activities that are determined to be a mechanical integrity issue</li> <li>Sustained variations in temperature outside of three standard deviations</li> </ul>
CO <sub>2</sub> Saturation	<ul style="list-style-type: none"> <li>Increased CO<sub>2</sub> saturations that indicate migration of CO<sub>2</sub> above the confining zone and are not a result of a mechanical integrity issues</li> </ul>
Groundwater Constituent Concentrations	<ul style="list-style-type: none"> <li>Changes in fluid and chemical content concentrations that indicate migration of injection zone fluids into formations overlying the confining zone, which are not a result of a mechanical integrity issue</li> <li>Should a statistically significant deviation from the baseline data collected from the above confining zone interval occur</li> </ul>
Bottomhole Injection Pressure	<ul style="list-style-type: none"> <li>Should bottomhole pressure exceed 90 percent of the calculated fracture pressure</li> </ul>
Well Integrity	<ul style="list-style-type: none"> <li>Change in pressure in the annulus system surrounding the injection well that indicates a loss of mechanical integrity in an injection well will be investigated</li> </ul>
Seismic Monitoring and Induced Seismicity	<ul style="list-style-type: none"> <li>Microseismic monitoring indicates the re-activation of faults or fractures that could propagate into the confining layer and impact containment</li> </ul>

Additional causes for AoR re-evaluation could include the extension of the CO<sub>2</sub> plume or pressure front beyond the initial plume predictions based on results of 3D seismic surveys; induced seismic events greater than M3.5 within the seismic monitoring area around the project; an exceedance of any operating conditions; or, if the data gathered during the Pre-Operational Testing Program result substantially changes to the current models and understanding of the subsurface.

Should any of the events occur that are detailed above, the project will discuss AoR re-evaluation procedures and timeline with the UIC Program Director to conclude if the re-evaluation is necessary.

## 5 References

- AK Steel Cleveland-Cliffs Steel Corporation. (March 15, 2021). *Ohio Environmental Protection Agency Division of Drinking and Ground Waters Underground Injection Control Permit to Operate Class I Hazardous Well; Ohio Permit UIC 05-09-001-THO-I*.
- (2022). *Attachment 1: Narrative*. Class VI Permit Application Narrative; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 10: ERP*. Emergency And Remedial Response Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 11: QASP*. Project Hoosier#1, Vault 4401.
- (2022). *Attachment 2: AoR and Corrective Action*. Area Of Review And Corrective Action Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 2: AOR and Corrective Action*. Area Of Review And Corrective Action Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 3: Financial Responsibility*. Financial Responsibility; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 4: Well Construction*. Injection Well Construction Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 5: Pre-Op Testing Program*. Pre-Operational Formation Testing Program; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 6: Well Operations*. Well Operation Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 7: Testing And Monitoring*. Testing And Monitoring Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 8: Well Plugging*. Project Hoosier#1, Vault 4401.
- (2022). *Attachment 9: Post-Injection Site Care*. Post-Injection Site Care And Site Closure Plan; Project Hoosier#1, Vault 4401.
- Collins, D.A., Nghiem, L.X., Li, Y.-K. and Grabenstetter, J.E. (May 1992). *"An Efficient Approach to Adaptive-Implicit Compositional Simulation with an Equation of State"*. SPE Res. Eng., Vol. 7 pp. 259-264.
- Degterev, A. Y. (2020). Multivariate Spatial Temporal Model of Gas Dynamic in Underground Gas Storage Based on Saturation Parameter from Well Logging Data. *SPE Russian Petroleum Technology Conference, Virtual, October 2020*.

INEOS (BP Lima) Nitriles. (August 22, 2016). *Ohio Environmental Protection Agency Division of Drinking and Ground Waters Underground Injection Control Permit to Operate Class I Hazardous Well; Ohio Permit UIC 03-02-005-PTO-I.*

INEOS USA LLC. (2015). *Class I Underground Injection Control Permit to Operate Renewal Applications.*

Nghiem, L.X. and Li, Y.-K. (September 4-8, 1989). *"Phase-Equilibrium Calculations for Reservoir Engineering and Compositional Simulation"*. Second International Forum on Reservoir Simulation, Alpbach, Austria.

Sullivan, D. (1995). *Natural Gas Fields of Indiana, Special Report 51*. Indiana Geological Survey Special Report 51.

Thomas, G.W. and Thurnau, D.H. (October 1983). *"Reservoir Simulation Using an Adaptive-Implicit Method"*. SPE, Vol. 23 pp. 759-768.

Vickery Environmental. (2021). *Ohio Environmental Protection Agency Division of Drinking and Ground Waters Underground Injection Control Permit to Operate Class I Hazardous Well; Ohio Permit UIC 03-72-011-PTO-I.*

Indiana is not a primacy state. No additional requirements

## CLASS VI AOR DOMAIN COORDINATES

### Instructions:

Please complete the applicable highlighted fields below and submit the updated version of the file via the GSDT. Provide the domain coordinates of your model domain based on one of the following examples (or in another appropriate format based on your mesh type) to define the area used in your model.

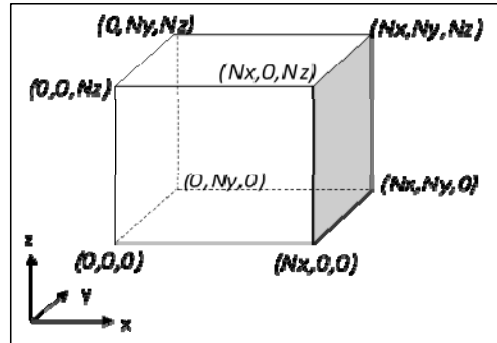
**Project Name:** Project Hoosier #1

**Date:** 7/7/2022

### Example 1 - Hexahedral Cartesian Mesh

If a hexahedral Cartesian mesh type is selected, it is recommended that you provide the x,y,z coordinates for each corner of the domain as shown below.

Node	X-coordinate	Y- coordinate	Z-coordinate
(0,0,0)	530951	1778776	2681
(Nx,0,0)	572951	1778776	2681
(0,Ny,0)	530951	1820776	2681
(Nx,Ny,0)	572951	1820776	2681
(0,0,Nz)	530951	1778776	1926
(Nx,0,Nz)	572951	1778776	1926
(0,Ny,Nz)	530951	1820776	1926
(Nx,Ny,Nz)	572951	1820776	1926



A dynamic model was created by extracting a sub-model from the larger static model to reduce the computer run-time to a practical level. All of the boundary conditions are of the Neumann (flux) type. The grid top and grid bottom were designated as no-flow (or zero flux) boundaries. Since the extent of the aquifer is thought to be much larger than the grid boundaries, an analytical aquifer function (Carter-Tracy Infinite Acting) was employed to simulate the pressure response of the aquifer and fluids were allowed to “leak” across the boundary. This analytical function was applied to all of the grid-blocks on the four sides of the model.

Capillary pressure not considered as data are not currently available, model will be updated based on results of core testing.

Capillary pressure not considered as data are not currently available, model will be updated based on results of core testing.

Capillary pressure not considered as data are not currently available, model will be updated based on results of core testing.

DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
Division of Oil and Gas  
606 State Office Building  
Indianapolis, Indiana 46204

API # 13 135 20022

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

<b>DESIGNATION</b> Operator <u>LARRY WILEY</u> Farm Name <u>LARRY WILEY</u> Well No. _____ PERMIT NO. <u>39344</u>	<b>TYPE OF COMPLETION</b> Dry Hole <u>X</u> Stratigraphic Test _____ Oil _____      Saltwater Disposal _____ Gas _____      Water Supply _____ Pressure Maintenance or      Gas Storage: _____ Secondary Recovery:      Injection - Extraction _____ Water Injection _____      Observation _____ Gas Injection _____																								
<b>TYPE OF WELL</b> New Well <u>✓</u> Workover _____    Deepening _____	<b>INITIAL PRODUCTION</b> Oil _____      Gas _____																								
<b>LOCATION</b> County <u>White River</u> Twp. <u>20N</u> Rge. <u>14E</u> Section <u>24</u> <u>SE</u> ¼ <u>SE</u> ¼ <u>SE</u> ¼ <u>704.60'</u> from S line <u>460.05'</u> from E line	<b>COMPLETION INTERVAL</b> Interval(s) <u>240</u> Formation Name(s) <u>Nigra Limestone</u>																								
<b>ELEVATION</b> <u>1110'</u>	<b>WELL TREATMENT</b> Shot _____ qts. _____ interval _____ Shot _____ qts. _____ interval _____ Acid _____ gals. _____ interval _____ Acid _____ gals. _____ interval _____ Fracture _____ gals. _____ interval _____ Fracture _____ gals. _____ interval _____																								
<b>TOTAL DEPTH</b> Driller's Log <u>240'</u> Electric Log _____	<b>CASING RECORD</b> <table style="width:100%; border-collapse: collapse;"> <thead> <tr> <th style="text-align: center;">Size</th> <th style="text-align: center;">Depth</th> <th style="text-align: center;">Sks Cement</th> <th style="text-align: center;">Csg Pulled</th> </tr> </thead> <tbody> <tr> <td style="text-align: center;"><u>8 7/8" CP</u></td> <td style="text-align: center;"><u>95'</u></td> <td></td> <td></td> </tr> <tr><td> </td><td> </td><td> </td><td> </td></tr> <tr><td> </td><td> </td><td> </td><td> </td></tr> <tr><td> </td><td> </td><td> </td><td> </td></tr> <tr><td> </td><td> </td><td> </td><td> </td></tr> </tbody> </table>	Size	Depth	Sks Cement	Csg Pulled	<u>8 7/8" CP</u>	<u>95'</u>																		
Size	Depth	Sks Cement	Csg Pulled																						
<u>8 7/8" CP</u>	<u>95'</u>																								
<b>OPERATIONAL DATES</b> Commenced <u>April 5</u> Completed <u>April 7</u>																									
<b>TOOLS</b> Rotary (interval) <u>0-240</u> Cable (interval) _____																									

**OCCURRENCE OF OIL AND GAS**

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
N/A		

The above information is complete and correct.

Date April 5 / 82

Address of Operator R.R. 4 Union City, Ind.

Signed

Larry Wiley  
Owner - Operator

Title

# FORMATION RECORD

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	35	Clay			
35	60	gravel			
60	77	Clay			
77	96	Gravel			
96	240	Limestone			

APR 1982  
RECEIVED  
Dept. of Natural Resources  
Div. of Oil & Gas





## WELL PLUGGING AFFIDAVIT

State Form 1115R

STATE OF INDIANA		SS:		Permit No. <b>39344</b>					
COUNTY OF <b>RANDOLPH</b>				Type of Bond <b>PERSONAL</b> <input checked="" type="checkbox"/> \$1,000 <input type="checkbox"/> \$5,000					
				Date Bond released <b>APR 15 1982</b>					
<b>DESIGNATION</b>		<b>LOCATION</b>							
Name of Operator <b>Larry Wiley</b>	County <b>RANDOLPH</b>	Township <b>20N</b>	Range <b>14E</b>						
Name of Farm <b>Larry Wiley</b>	Section <b>1</b>	1/4 <b>SE</b> 1/4 <b>SE</b> 1/4							
Well No. <b>1</b>	From N/S line <b>704.60' SL</b>	From E/W line <b>460.05' EL</b>							
<b>ELEVATION</b> <b>1110'</b>	Civil Township <b>White River</b>								
Date Permit issued <b>4-3-80</b>	Date drilling started <b>4-80</b>	Date drilling completed <b>4-80</b>	Kind of drilling tools used <b>ROTARY</b>	Total depth <b>240'</b>					
Has this well ever produced oil or gas OIL: <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No    GAS: <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No			Remarks: <b>LEFT FOR WATER WELL</b>						
<b>DETAILS OF PLUGGING</b>									
<b>MATERIALS USED</b> (Rotary Mud, Cement, or other Materials)	<b>FROM</b> (Feet)	<b>TO</b> (Feet)	<b>MATERIALS USED</b> (Rotary Mud, Cement, or other Materials)	<b>FROM</b> (Feet)					
		<b>240'</b>							
IF WORKABLE COAL BEDS WERE ENCOUNTERED IN THIS HOLE, DESCRIBE THE METHOD EMPLOYED TO PROTECT SAME. (A workable coal bed is 24 inches or more in thickness above 1,200 feet in depth)									
Please Note: The bond for this well cannot be released until all four squares below are checked "Yes"									
Have pits, cellar and other excavations been filled? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	Have equipment, concrete bases and debris been removed? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	Has surface casing been cut off below plow depth? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	Has well-site been levelled? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No						
<b>CASING RECORD</b>									
<b>SIZE</b>	<b>PUT IN WELL</b>	<b>PULLED OUT</b>	<b>LEFT IN WELL</b>	<b>REMARKS</b>	<b>SIZE</b>	<b>PUT IN WELL</b>	<b>PULLED OUT</b>	<b>LEFT IN WELL</b>	<b>REMARKS</b>
	Feet	Feet	Feet			Feet	Feet	Feet	
<b>8"</b>	<b>unknown</b>								
Signature of person, Firm or Corporation having custody or control of well <b>Larry Wiley</b>					Signature of party supervising plugging of well <b>Virgil E. Lowe</b>				
Per. (Name) <b>Virgil E. Lowe</b>					Title <b>Field Inspector</b>				
Street Address <b>RR #4</b>		City, State, Zip <b>UNION CITY, IN. 47390</b>			Street Address <b>4009 Virginia</b>		City, State, Zip <b>MUNCIE, IN. 47304</b>		
STATE OF INDIANA COUNTY OF <b>RANDOLPH</b> SS:					Notary's Signature <b>Virgil E. Lowe</b>				
Subscribed and sworn to before me this <b>13</b> day of <b>April</b> 19 <b>82</b>					Notary's Name Typed or Printed <b>Virgil E. Lowe</b>				
County of Residence <b>Delaware</b>		Commission Expiration Date <b>2-14-84</b>							

# CERTIFICATE OF COMPLIANCE



Issued by:

STATE OF INDIANA  
DEPARTMENT OF NATURAL RESOURCES  
DIVISION OF OIL AND GAS  
911 State Office Building  
Indianapolis, Indiana 46204

Instructions: The owner or operator shall file this certificate in the office of the recorder of the county below within 90 days from the certificate issue date (IC 13-4-7-23H).

STATE OF INDIANA	SS:	Permit No.
COUNTY OF <u>RANDOLPH</u>		<u>39344</u>

I, Virgil E. Lowe, a duly qualified District Oil and Gas Supervisor of the State of Indiana, do hereby certify that I have supervised the plugging and abandoning of the following well:

Name of Farm <u>Larry Wiley</u>	Well No. <u>1</u>	County <u>Randolph</u>	Township <u>20N</u>	Range <u>14E</u>
From N/S line	From E/W line	Section <u>24</u>	<u>— 1/4 SE 1/4 SE 1/4</u>	

## CASING LEFT IN WELL

SIZE	FEET	INCHES	REMARKS
<u>8"</u>	<u>UNKNOWN</u>		<u>CONVERTED TO WATER WELL</u>

## DETAILS OF PLUGGING

MATERIALS USED (Rotary Mud, Cement, or other Materials)	FROM (Feet)	TO (Feet)	MATERIALS USED (Rotary Mud, Cement, or other Materials)	FROM (Feet)	TO (Feet)
<u>Water well</u>	<u>240'</u>				

Date Plugging Completed (Month) <u>April</u>	Day <u>13</u>	Year <u>1982</u>	Date Abandonment Completed (Month)	Day	Year <u>19</u>
---	------------------	---------------------	------------------------------------	-----	-------------------

I further certify that said well has been plugged and abandoned in accordance with the provisions of IC 13-4-7, Indiana General Assembly, and Rules and Regulations adopted pursuant thereto.

Date Certificate Issued (Month) <u>April</u>	Day <u>13</u>	Year <u>1982</u>	Oil & Gas Inspector's Signature <u>Virgil E. Lowe</u>
This Instrument prepared by <u>Virgil E. Lowe</u>			



ASSUMPTION OF RESPONSIBILITY STATEMENT  
(BY LANDOWNER OF CONVERTING TO WATER WELL)

State Form 107

Permit No 39344

DEPARTMENT OF NATURAL RESOURCES  
DIVISION OF OIL AND GAS  
911 STATE OFFICE BUILDING  
INDIANAPOLIS, INDIANA 46204



LANDOWNER'S STATEMENT

I am the owner of the lands on which an oil and/or gas well was drilled by LARRY Wiley Well Drilling (Operator)  
located SE 1/4 SE 1/4 SE 1/4, Section 24, Township 20N, Range 14E, County Randolph,  
Indiana, designated as LARRY Wiley (Name) 1 (No.) and which has been abandoned  
according to the requirements provided by the Indiana Statutes; except, at my request, the well was left unplugged at 240 feet  
below surface; which I can use to good advantage in the operation of my farm by converting same for fresh water purposes.  
I hereby release the operator of the well of all responsibility and statutory requirements for the further plugging of said well.

The undersigned hereby swears (or affirms) the facts in the foregoing are true.

Date

Month

Day

Year

April

5

1982

Landowner's Signature

Larry J. Wiley

STATE OF INDIANA

SS:

COUNTY OF Randolph

Subscribed and sworn to before me this 5<sup>th</sup> day of April, 19 82.

County of Residence

Randolph

Commission Expiration Date

March 9, 1985

Notary's Signature

Carolyn Wiley

Notary's Name Typed

Carolyn Wiley



## DEPARTMENT OF NATURAL RESOURCES

STATE OF INDIANA

## Division of Oil and Gas

**911A State Office Building**

Indianapolis, Indiana 46204

API # 13 135 20028

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

**TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL**

**NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.**

<b>DESIGNATION</b> Operator <u>Pioneer Drilling Company, Inc.</u> Farm Name <u>Carl Tibbetts</u> Well No. <u>#2</u> <hr/> PERMIT NO. <u>48735</u> <hr/> <b>TYPE OF WELL</b> New Well <input checked="" type="checkbox"/> Workover <input type="checkbox"/> Deepening <input type="checkbox"/> <hr/> <b>LOCATION</b> County <u>Randolph</u> Twp. <u>20N</u> Rge. <u>15E</u> Section <u>19</u> $\frac{1}{4}$ <u>SE</u> $\frac{1}{4}$ <u>SE</u> $\frac{1}{4}$ <u>330</u> from <u>N</u> line <u>330</u> from <u>E</u> line <div style="text-align: center;"> <div style="border: 1px solid black; border-radius: 50%; width: 10px; height: 10px; display: inline-block; margin: 0 5px;"></div> <div style="border: 1px solid black; border-radius: 50%; width: 10px; height: 10px; display: inline-block; margin: 0 5px;"></div> </div> <hr/> <b>ELEVATION</b> <u>1111.9</u> Electric or Other Geophysical Log Run <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No <hr/> <b>TOTAL DEPTH</b> Driller's Log <u>1148</u> Electric Log <input type="checkbox"/> <hr/> <b>OPERATION DATES</b> Commenced <u>11-2-88</u> Completed <u>11-8-88</u> <hr/> <b>TOOLS</b> Rotary (interval) <u>0-1148</u> Cable (interval) <u>          </u>	<b>TYPE OF COMPLETION</b> Dry Hole <input type="checkbox"/> Stratigraphic Test <input type="checkbox"/> Oil <input type="checkbox"/> Saltwater Disposal <input type="checkbox"/> Gas <input checked="" type="checkbox"/> Water Supply <input type="checkbox"/> Pressure Maintenance or Secondary Recovery: <input type="checkbox"/> Water Injection <input type="checkbox"/> Injection-Extraction <input type="checkbox"/> Gas Injection <input type="checkbox"/> Observation <input type="checkbox"/> <hr/> <b>INITIAL PRODUCTION</b> Oil <input type="checkbox"/> Gas <u>30 MCF</u> <hr/> <b>COMPLETION INTERVAL</b> Interval(s) <u>1108-1148</u> Formation Name(s) <u>Trenton</u> <hr/> <b>WELL TREATMENT</b> <table style="width: 100%;"> <tr> <td>Shot</td> <td>qts.</td> <td>interval</td> </tr> <tr> <td>Shot</td> <td>qts.</td> <td>interval</td> </tr> <tr> <td>Acid</td> <td><u>500</u> qts.</td> <td><u>1108-1148</u> interval</td> </tr> <tr> <td>Acid</td> <td><u>3,000</u> gals.</td> <td><u>1108-1148</u> interval</td> </tr> <tr> <td>Fracture</td> <td>gals.</td> <td>interval</td> </tr> <tr> <td>Fracture</td> <td>gals.</td> <td>interval</td> </tr> </table> <hr/> <b>CASING RECORD</b> <table style="width: 100%;"> <thead> <tr> <th>Size</th> <th>Depth</th> <th>Sks Cement</th> <th>Csg Pulled</th> </tr> </thead> <tbody> <tr> <td>10"</td> <td>97'</td> <td>-0-</td> <td>-0-</td> </tr> <tr> <td>7"</td> <td>545'</td> <td>100</td> <td>-0-</td> </tr> <tr> <td>4"</td> <td>1113'</td> <td>40</td> <td>-0-</td> </tr> </tbody> </table>	Shot	qts.	interval	Shot	qts.	interval	Acid	<u>500</u> qts.	<u>1108-1148</u> interval	Acid	<u>3,000</u> gals.	<u>1108-1148</u> interval	Fracture	gals.	interval	Fracture	gals.	interval	Size	Depth	Sks Cement	Csg Pulled	10"	97'	-0-	-0-	7"	545'	100	-0-	4"	1113'	40	-0-
Shot	qts.	interval																																	
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Size	Depth	Sks Cement	Csg Pulled																																
10"	97'	-0-	-0-																																
7"	545'	100	-0-																																
4"	1113'	40	-0-																																

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
1112-1134	ls	Show of Gas

INFORMATION RELEASED  
 DATE 11-9-89

The above information is complete and correct.

Date 12-23-88

Signed

Title

Gary R. Cooper

President

Address of Operator Rt #2, Box 77 Payne, Ohio 45880

State Form 37136

GIVE COMPLETE FORMATION RECORD ON REVERSE SIDE

# FORMATION RECORD

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	90	Glacial Drift			
90	160	Limestone			
160	162	Clay Filled Fracture			
162	315	Limestone			
315	500	Lime and Shale			
500	1108	Shale			
1108	1148	Trenton Limestone			





# PLUGGING AND ABANDONMENT REPORT

State Form 1115R3

## OPERATOR'S NOTE:

- As soon as the site restoration is complete, the Operator is to contact the Inspector.
- This report must be filed in the office of the recorder of the county in which the well was located **WITHIN 90 days** of issuance.
- Photocopy form for distribution

## FOR OFFICE USE ONLY

Bond type <input type="checkbox"/> \$1,000 <input checked="" type="checkbox"/> \$2,000 <input type="checkbox"/> \$5,000 <input type="checkbox"/> \$30,000	Date bond released 8-22-89
Well type <input checked="" type="checkbox"/> Dry <input type="checkbox"/> Oil <input type="checkbox"/> Gas <input type="checkbox"/> Disposal <input type="checkbox"/> Enhanced recovery <input type="checkbox"/> Gas Storage <input type="checkbox"/> Observation <input type="checkbox"/> Non-potable water supply <input type="checkbox"/> Geological or structure test	

## PLUGGING

Name of Operator PIONEER Drilling Co. INC.	Date well plugged 7-26-89
Address of Operator P.R. #2 BOX 77 PAYNE, OH. 45880	Permit number 48735
Name of lease CARL TIBBETTS	Well number 1

County of well location RANDOLPH	Section 19	Township 20N	Range 15E	1/4 SE	1/4 SE	1/4 XX	330' feet from North / South Line 330' feet from East / West Line	Total Depth (feet) 1148'
-------------------------------------	---------------	-----------------	--------------	-----------	-----------	-----------	--	-----------------------------

CASING RECORD	STRING #4	STRING #3	STRING #2	STRING #1
Casing or tubing diameter ..... (outside / inches)		4 1/2"	7"	10"
Amount set ..... (feet)		1110'	545'	97'
Amount left in well ..... (feet)		710'	545'	97'
Hole size ..... (diameter / inches)				
Cement used to set ..... (cubic feet)		45 SKS	100 SKS	
PLUGGING RECORD	PLUG #1	PLUG #2	PLUG #3	PLUG #4
Hole or pipe diameter ..... (inside / inches)	4 1/2"	4 1/2"	4 1/2"	7"
Material used	Cement	Per Gravel	Cement	Cement
Depth to bottom of plug	1148'	1320'	600'	400'
Depth to top of plug ..... (calculated)	1320'	600'	400'	0'
Amount Used ..... (sacks)	12 SKS	6 Ton	115 SKS	

I certify that the information provided above is correct and accurate to the best of my knowledge.

Printed name of Operator, Operator's Rep., or person controlling well Pioneer Drilling	Signature [Signature]	Date signed 8-1-89
Printed name of Field Inspector Virgil E. Lowe	Signature [Signature]	Date signed 8-1-89
Address of Field Inspector (Street, city, state, ZIP code) 4009 Virginia Ave. Muncie, Ind, 47304		Phone number of Field Inspector 317-288-0708

## ABANDONMENT

Date abandonment completed and site inspected (Month, day, year)	
Abandonment requirements (check if completed) <input checked="" type="checkbox"/> Excavations filled <input checked="" type="checkbox"/> Equipment and debris removed <input checked="" type="checkbox"/> Top 3 feet of casing removed <input checked="" type="checkbox"/> Site leveled	
NOTE: Appropriate "Assumption of Responsibility" form(s) must be attached for any box(es) left unchecked above.	
I certify that this well has been abandoned in accordance with provisions of IC 13-4-7 and 310 IAC 7-1.	
Signature of Field Inspector [Signature]	Date signed 8-18-89



# APPLICATION FOR WELL PERMIT

State Form 21096R

## INSTRUCTIONS:

- PRINT or TYPE all information.
- Return application to:

INDIANA DEPARTMENT OF NATURAL RESOURCES  
DIVISION OF OIL AND GAS  
911B State Office Building  
Indianapolis, Indiana 46204-2267

## IMPORTANT:

- Any permit obtained through fraud or misrepresentation will be revoked.
- Any application not fully completed will automatically be returned.

### FOR OFFICE USE ONLY - DO NOT WRITE IN THIS SPACE

Fee amount <u>100<sup>00</sup></u>	Check number <u>1116</u>	Bond type <u>SB 2,000</u>	Bond number <u>13-0130-10682-88-7</u>
Permit number <u>48736</u>	API number 13 - <u>135-20029</u>	Application number <b>38855</b>	
Signature of approval <i>Michael P. Nickerson</i>		Date of approval	

### GENERAL INFORMATION

Type of application (Check one)	
<input type="checkbox"/> Change of location (C.O.L.)	<input type="checkbox"/> Workover (O.W.W.O.)
<input type="checkbox"/> Deepen (O.W.D.D.)	<input type="checkbox"/> Convert
<input checked="" type="checkbox"/> New well	
Well type, if converted or new (check one)	
<input checked="" type="checkbox"/> Oil	<input checked="" type="checkbox"/> Gas
<input type="checkbox"/> Disposal	<input type="checkbox"/> Enhanced recovery
<input type="checkbox"/> Gas storage or observation	<input type="checkbox"/> Non-potable water supply
<input type="checkbox"/> Geological or structure test	
Former permit number	
Name of operator <u>Pioneer Drilling Company, Inc.</u>	Telephone number <u>4 1 9 - 26 3 - 2 3 1 5</u>
Address of Operator (Street, city, state, ZIP code) <u>Rt #2, Box 77 Payne, Ohio 45880</u>	
Name of Drilling Contractor <u>Pioneer Drilling Company, Inc.</u>	Telephone number <u>4 1 9 - 26 2 - 2 3 1 5</u>
Address of Drilling Contractor (Street, city, state, ZIP code) <u>Rt #2, Box 77 Payne, Ohio 45880</u>	
Permit to be sent to (Check one)	
<input checked="" type="checkbox"/> Operator	<input type="checkbox"/> Contractor
<input type="checkbox"/> Other (Specify name and address)	
Date drilling is expected to start <u>September 30, 1988</u>	
Drilling tools to be used	
<input checked="" type="checkbox"/> Rotary	<input type="checkbox"/> Cable
Is the Operator or any of its agents officers or employees in violation of the Indiana Oil and Gas law at this time?	
<input type="checkbox"/> Yes	<input checked="" type="checkbox"/> No
Is an assumed business name used?	
<input checked="" type="checkbox"/> Yes	<input type="checkbox"/> No
If assumed business name is used, in what county is it registered? <u>Paulding County, Ohio</u>	
What is the applicant?	
<input type="checkbox"/> Partnership	<input type="checkbox"/> Firm
<input checked="" type="checkbox"/> Corporation	
If a corporation, is the operation authorized by your charter?	
<input checked="" type="checkbox"/> Yes	<input type="checkbox"/> No
Name of Surety Bond Agency <u>United States Fidelity and Guaranty</u>	
Address of Surety Bond Agency (Street, city, state, ZIP code) <u>Suite 1012, 105 East Fourth Street Cincinnati, Ohio 45202</u>	
Type of Surety Bond	
<input type="checkbox"/> Money Order	<input type="checkbox"/> Certified Check
<input type="checkbox"/> Certificate of Deposit	<input checked="" type="checkbox"/> Surety
Bond amount	
<input checked="" type="checkbox"/> \$2,000	<input type="checkbox"/> \$5,000
<input type="checkbox"/> \$30,000	

WELL LOCATION					
Name of lease <div style="text-align: center; font-size: 1.2em;">Rein &amp; Esther Spille</div>					
Well name <div style="text-align: center; font-size: 1.2em;">Rein Spille</div>				Well number <div style="text-align: center; font-size: 1.2em;">1</div>	
Surface elevation <div style="text-align: center; font-size: 1.2em;">1107.7</div>					
Method of determining elevation <div style="text-align: center; font-size: 1.2em;">U.S.G.S. B.M. D-39 ±23' east of C/L C.R. 400 E &amp; ±70' south rail of railroad 1105.42</div>					
Well location from north / south line (Feet) <div style="text-align: center; font-size: 1.2em;">330' North of South line</div>			Well location from east / west line (Feet) <div style="text-align: center; font-size: 1.2em;">330' West of <del>West</del> <sup>East</sup> line</div>		
Section <div style="text-align: center; font-size: 1.2em;">20</div>	Township <div style="text-align: center; font-size: 1.2em;">20 North</div>	Range <div style="text-align: center; font-size: 1.2em;">15 East</div>	SE <div style="text-align: center; font-size: 1.2em;">1/4</div>	NW <div style="text-align: center; font-size: 1.2em;">1/4</div>	
County <div style="text-align: center; font-size: 1.2em;">Randolph</div>					
Civil township <div style="text-align: center; font-size: 1.2em;">Wayne</div>					
Total lease acreage <div style="text-align: center; font-size: 1.2em;">40</div>					
Acreage allotted to well <div style="text-align: center; font-size: 1.2em;">40</div>					
Is drilling unit communitized or pooled? (If yes, a copy of the Declaration Agreement must be attached) <div style="text-align: center;"> <input type="checkbox"/> Yes    <input checked="" type="checkbox"/> No         </div>					
If a copy of the Declaration Agreement is already on file, what permit number was it submitted with?					
<b>If applicable, answer one the following:</b>					
Number of feet well will be located to the nearest producing well in the same geological formation. <div style="text-align: center; font-size: 1.2em;">1,320' +</div>					
Are there any drilling, temporarily abandoned or unplugged wells within a 1/2 mile radius of the well that are not operated by the applicant? (If yes, attach a copy of the letter and certified receipt that was sent to the operator(s) of the wells.) <div style="text-align: center;"> <input type="checkbox"/> Yes    <input checked="" type="checkbox"/> No         </div>					

WELL CONSTRUCTION	
Casing size (All casing programs are required to conform with API specifications as required by 310 IAC 7-1)	
10 3/4 " Conductor (through all glacial drift approx 100')	----- 7 " Casing (throught all potable water zones into shale approx. 500')
Casing weight <div style="text-align: center; font-size: 1.2em;">36"</div>	----- 17"
Casing length <div style="text-align: center; font-size: 1.2em;">R-1</div>	----- R-2
Tubing	
Packers	
Plugs / Plugbacks	
Centralizers	
Cement	
Cement additives (If any) <div style="text-align: center; font-size: 1.2em;">2% CaCl</div>	
Cement volume <div style="text-align: center; font-size: 1.2em;">8-10 Sacks</div>	----- 2% CaCl <div style="text-align: center; font-size: 1.2em;">150-170 Sacks (to Surface)</div>
<b>Answer only if applying for Oil, Gas, or Geological or Structure test well:</b>	
Proposed total depth of well <div style="text-align: center; font-size: 1.2em;">1,250'</div>	
Name of lowest geological formation to be drilled <div style="text-align: center; font-size: 1.2em;">Trenton Limestone</div>	
Type of well (Check one) <div style="text-align: center;"> <input type="checkbox"/> Wildcat    <input checked="" type="checkbox"/> Pool         </div>	Name of pool <div style="text-align: center; font-size: 1.2em;">Harrisville</div>

**Answer only if applying for enhanced recovery, disposal or gas storage well:**

Geological formation to be injected / disposed

Approximate intervals of injection / disposal

Source of water or gas

Estimate of volume (barrels or MCF) to be injected / disposed daily

Average daily injection / disposal pressure

**Answer only if applying for gas storage observation well:**

Proposed total depth of well

Name of lowest geological formation to be drilled

Purpose of observation well

Method of operation (Include frequency and technique used to monitor)

**Answer only if applying for non-potable water supply well:**

Proposed total depth of well

Water production interval

Name of geological formation being produced

Estimated amount of water produced daily

Proposed use of water

**AFFIRMATION**

**I affirm under the penalty for perjury that the information provided in this application is true to the best of my knowledge and belief.**

**Pioneer Drilling Company, Inc.**

Signature of Operator or Authorized Representative

Gary R. Cooper

President

Date signed (Month, day, year)

8-19-88

- To be completed by surveyor.
- Clearly indicate the section, township, and range on the survey.
- Use the surveyors notes to explain deviations from a standard location such as topography, irregular, correctional or fractional sections, military donations and surveys.

- Outline leased area, drilling unit allotment, and spot well location.
- Use a scale of 6" = 1 mile.

- Outline leased area and spot well location.
- Draw  $\frac{1}{2}$  mile radius from proposed well and spot all other drilling, temporarily abandoned or unplugged wells not operated by the applicant within the radius.
- Use a scale of 3" = 1 mile.

[illegible]

Note: Location of well is from apparent property lines, as a boundary survey was not performed.

Spille Well #1	
Ground elevation at well	1107.7

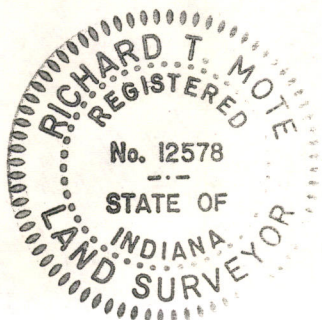
330

330'

Section 20

C.R. 500 E

## Surveyors' seal



*I hereby certify that to the best of my knowledge and belief the proposed location of the above described well, fixed as the result of an instrument survey made by me in compliance with the requirements of the law of Indiana, is truly and correctly set forth hereon.*

Signature of registered Indiana land surveyor

Date signed (Month, day, year)

Richard T. Mote, P.E. *Richard T. Mote*

August 11, 1988

Address (Street, city, state, ZIP code)

Phone number	
--------------	--

113 $\frac{1}{2}$  South Main Street, Winchester, IN 47394

$$3\ 17\ |\ -\ 5\ 84\ |\ -\ 8\ 8\ 0\ 6$$

Indiana Registration number or date of Commission approval

Registered Surveyor # 12578

**Affix surveyors' seal to the left (Required by Section 16, Registration Act).**



# REPORT OF PERMIT ACTIVITY

State Form 42029 (12-87)

Department of Natural Resources

ST. RD 32 ON 500E  
PAST 500E 4/10 MIONR

PERMIT DATA		
Operator Pioneer Drilling Co Inc		Permit Number 48736
Address (Street, number, city and ZIP code) RR #2, Box 77 Payne, OH 45880		Type Oil/Gas
		Date Issued 8-25-88
		Telephone Number (419) 263-2315
Transferred To:		Date
Transferred To:		Date
Transferred To:		Date

LOCATION DATA				
County Randolph	Political Township Wayne	Section 20	Township 20N	Range 15E
Surface Elevation 1107.7'	330' <del>X</del> N line 330' <del>X</del> W line	SE 1/4	NW 1/4	XX 1/4
Lease Rein & Esther Spille			Well Number #1	

WELL DATA				
Total Depth 1250'		Pool Name Harrisville		Date
Plugback Depth <del>7'-1250'</del>		Plugback Materials and Amounts NOT Going To Dry /		Date <del>12-22-88</del> 8-25-89
CASING		ACTIVITY		DATE
Size <del>8 5/8"</del>	Length <del>7'-1250'</del>	Cement	Permit Expired	BY VL
			Well Operating	
			T.A. Until	
			Plugged	
			Abandoned	
M.I.T.	BY	RESULT	REASON	
FORMATION DATA				
INTERVAL	NAME		COMMENTS	
—				
—				
—				
—				

[illegible]

**DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
Division of Oil and Gas  
911A State Office Building  
Indianapolis, Indiana 46204**

**TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL**  
**NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.**

## OCCURRENCE OF OIL AND GAS


[illegible]

Signed Gary R. Cooper  
Title Gary R. Cooper President

State Form 37136

GIVE COMPLETE FORMATION RECORD ON REVERSE SIDE

# FORMATION RECORD

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	85	Glacial Drift			
85	310	Limestone			
310	500	Lime and Shale			
500	560	Shale			
560	900	Grey Shale			
900	1105	Brown Shale			
1105	1151	Trenton Limestone			
<p style="text-align: center;">INFORMATION RELEASED</p> <p style="text-align: center;">DATE <u>1-5-90</u></p> <p style="text-align: center;">BY <u>lr</u></p>					
<p style="text-align: center;">  </p>					



# PLUGGING AND ABANDONMENT REPORT

State Form 1115R3

## OPERATOR'S NOTE:

- As soon as the site restoration is complete, the Operator is to contact the Inspector.
- This report must be filed in the office of the recorder of the county in which the well was located **WITHIN 90 days** of issuance.
- Photocopy form for distribution

## FOR OFFICE USE ONLY

Bond type	Date bond released
<input type="checkbox"/> \$1,000 <input checked="" type="checkbox"/> \$2,000 <input type="checkbox"/> \$5,000 <input type="checkbox"/> \$30,000	8-22-89
Well type	
<input checked="" type="checkbox"/> Dry <input type="checkbox"/> Oil <input type="checkbox"/> Gas <input type="checkbox"/> Disposal <input type="checkbox"/> Enhanced recovery <input type="checkbox"/> Gas Storage <input type="checkbox"/> Observation <input type="checkbox"/> Non-potable water supply <input type="checkbox"/> Geological or structure test	

## PLUGGING

Name of Operator						Date well plugged	
Pioneer Drilling Co., Inc.						8-3-89	
Address of Operator						Permit number	
R.R. #2 Box 77 Payne, Oh. 45880						48737	
Name of lease						Well number	
Powers Farms of Union City, Inc.						1	
County of well location	Section	Township	Range	1/4	1/4	Total Depth (feet)	
RANDOLPH	20	20N	15E	SW	NW	X	1151
						330 feet from North / South Line	
						990 feet from East / West Line	
CASING RECORD				STRING # 4	STRING # 3	STRING # 2	STRING # 1
Casing or tubing diameter ..... (outside / inches)						7"	10"
Amount set ..... (feet)						560'	92'
Amount left in well ..... (feet)						560'	92'
Hole size ..... (diameter / inches)						425Ks	
Cement used to set ..... (cubic feet)						925Ks	
PLUGGING RECORD				PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4
Hole or pipe diameter ..... (inside / inches)				6 1/2"	7"		
Material used				PEARL AUC / CEMENT			
Depth to bottom of plug				1151'	500'		
Depth to top of plug ..... (calculated)				500'	0'		
Amount Used ..... (sacks)					115 SKS		

I certify that the information provided above is correct and accurate to the best of my knowledge.

Printed name of Operator, Operator's Rep., or person controlling well	Signature	Date signed
Pioneer Drilling Co. Inc.	[Signature]	8-3-89
Printed name of Field Inspector	Signature	Date signed
Virgil E. Lowe	[Signature]	8-3-89
Address of Field Inspector (Street, city, state, ZIP code)		Phone number of Field Inspector
4009 Virginia Ave. MUNCIE, IND. 47304		317-288-0708

## ABANDONMENT

Date abandonment completed and site inspected (Month, day, year)	
Abandonment requirements (check if completed)	
<input checked="" type="checkbox"/> Excavations filled	<input checked="" type="checkbox"/> Equipment and debris removed
<input checked="" type="checkbox"/> Top 3 feet of casing removed	<input checked="" type="checkbox"/> Site leveled
NOTE: Appropriate "Assumption of Responsibility" form(s) must be attached for any box(es) left unchecked above.	
I certify that this well has been abandoned in accordance with provisions of IC 13-4-7 and 310 IAC 7-1.	
Signature of Field Inspector	Date signed
Virgil E. Lowe	8-18-89

COPY SENT TO  
PETROLEUM SECTION

## DEPARTMENT OF NATURAL RESOURCES

API # 13 135 20031STATE OF INDIANA  
Division of Oil and Gas  
911A State Office Building  
Indianapolis, Indiana 46204

## WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

<b>DESIGNATION</b> Operator <u>Pioneer Drilling Company, Inc.</u> Farm Name <u>Larry Bentz</u> Well No. <u>2</u>		<b>TYPE OF COMPLETION</b> Dry Hole _____ Oil _____ Gas <u>X</u> Pressure Maintenance or Secondary Recovery: Water Injection _____ Gas Injection _____ Stratigraphic Test _____ Saltwater Disposal _____ Water Supply _____ Gas Storage _____ Injection-Extraction _____ Observation _____																									
PERMIT NO. <u>48888</u>		<b>INITIAL PRODUCTION</b> Oil _____ Gas <u>15 MCF</u>																									
<b>TYPE OF WELL</b> New Well <u>X</u> Workover _____ Deepening _____		<b>COMPLETION INTERVAL</b> Interval(s) <u>1109-1156</u> Formation Name(s) <u>Trenton Limestone</u>																									
<b>LOCATION</b> County <u>Randolph</u> Twp. <u>20N</u> Rge. <u>15E</u> Section <u>29</u> $\frac{1}{4}$ <u>SW</u> $\frac{1}{4}$ <u>NW</u> $\frac{1}{4}$ <u>330</u> from <u>N</u> line <u>330</u> from <u>E</u> line <u>W</u> (S)		<b>WELL TREATMENT</b> <table border="0"> <tr><td>Shot</td><td>qts.</td><td>_____</td><td>interval</td></tr> <tr><td>Shot</td><td>qts.</td><td>_____</td><td>interval</td></tr> <tr><td>Acid</td><td>qts.</td><td>_____</td><td>interval</td></tr> <tr><td>Acid</td><td>gals.</td><td>_____</td><td>interval</td></tr> <tr><td>Fracture</td><td>gals.</td><td>_____</td><td>interval</td></tr> <tr><td>Fracture</td><td>gals.</td><td>_____</td><td>interval</td></tr> </table>		Shot	qts.	_____	interval	Shot	qts.	_____	interval	Acid	qts.	_____	interval	Acid	gals.	_____	interval	Fracture	gals.	_____	interval	Fracture	gals.	_____	interval
Shot	qts.	_____	interval																								
Shot	qts.	_____	interval																								
Acid	qts.	_____	interval																								
Acid	gals.	_____	interval																								
Fracture	gals.	_____	interval																								
Fracture	gals.	_____	interval																								
<b>ELEVATION</b> <u>1120.7</u> Electric or Other Geophysical Log Run <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No		<b>CASING RECORD</b> <table border="0"> <tr><th>Size</th><th>Depth</th><th>Sks Cement</th><th>Csg Pulled</th></tr> <tr><td>8"</td><td><u>105</u></td><td><u>-0-</u></td><td><u>-0-</u></td></tr> <tr><td>7"</td><td><u>322</u></td><td><u>-0-</u></td><td><u>322</u></td></tr> <tr><td>4"</td><td><u>1113</u></td><td><u>150 sack</u></td><td><u>-0-</u></td></tr> </table>		Size	Depth	Sks Cement	Csg Pulled	8"	<u>105</u>	<u>-0-</u>	<u>-0-</u>	7"	<u>322</u>	<u>-0-</u>	<u>322</u>	4"	<u>1113</u>	<u>150 sack</u>	<u>-0-</u>								
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4"	<u>1113</u>	<u>150 sack</u>	<u>-0-</u>																								
<b>TOTAL DEPTH</b> Driller's Log <u>1156</u> Electric Log _____																											
<b>OPERATION DATES</b> Commenced <u>12-12-88</u> Completed <u>12-19-88</u>																											
<b>TOOLS</b> Rotary (interval) <u>0- 1156</u> Cable (interval) _____																											

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
1109-1156	ls	Show of Gas

The above information is complete and correct.

Signed Gary R. Cooper President  
Title \_\_\_\_\_Date 12-27-88  
Address of Operator Rt #2, Box 77 Payne, Ohio 45880  
State Form 37136

GIVE COMPLETE FORMATION RECORD ON REVERSE SIDE

# FORMATION RECORD

From	To	Rock Type describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	101	Glacial Drift			
101	310	Limestone			
310	500	Lime and Shale			
500	905	Gray Shale			
905	1109	Brown Shale			
1109	1156	Trenton Limestone			
<p style="text-align: center;"> <b>INFORMATION RELEASED</b>  <b>DATE</b> <u>1-5-90</u>  <b>BY</b> <u>lr</u> </p>					





# PLUGGING AND ABANDONMENT REPORT

State Form 1115R3

## OPERATOR'S NOTE:

- As soon as the site restoration is complete, the Operator is to contact the Inspector.
- This report must be filed in the office of the recorder of the county in which the well was located **WITHIN 90 days** of issuance.
- Photocopy form for distribution

### FOR OFFICE USE ONLY

Bond type	Date bond released
<input type="checkbox"/> \$1,000 <input checked="" type="checkbox"/> \$2,000 <input type="checkbox"/> \$5,000 <input type="checkbox"/> \$30,000	8-22-89
Well type	
<input type="checkbox"/> Dry <input type="checkbox"/> Oil <input checked="" type="checkbox"/> Gas <input type="checkbox"/> Disposal <input type="checkbox"/> Enhanced recovery <input type="checkbox"/> Gas Storage <input type="checkbox"/> Observation <input type="checkbox"/> Non-potable water supply <input type="checkbox"/> Geological or structure test	

### PLUGGING

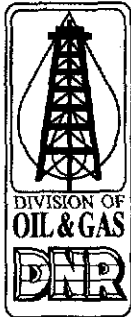
Name of Operator						Date well plugged	
Pioneer Drilling Co.						8-4-89	
Address of Operator						Permit number	
R.R. 2 Box 77 Payne, Oh. 45880						48888	
Name of lease						Well number	
LARRY BENTZ						1	
County of well location	Section	Township	Range	1/4	1/4	1/4	Total Depth (feet)
RANDOLPH	29	20N	15E	XX	SW	NW	1156'
Casing Record						STRING # 4	STRING # 3
Casing or tubing diameter (outside / inches)						4 1/2"	7"
Amount set (feet)						1113'	322'
Amount left in well (feet)						1113'	0'
Hole size (diameter / inches)							
Cement used to set (cubic feet)						150 SKS	
PLUGGING RECORD						PLUG # 1	PLUG # 2
Hole or pipe diameter (inside / inches)						4 1/2"	4 1/2"
Material used						Cement	Pea Gravel
Depth to bottom of plug						1156'	500'
Depth to top of plug (calculated)						1100'	0'
Amount Used (sacks)						12 SKS	48 SKS

I certify that the information provided above is correct and accurate to the best of my knowledge.

Printed name of Operator, Operator's Rep., or person controlling well	Signature	Date signed
Pioneer Drilling Co.	Robert Cooper	8-4-89
Printed name of Field Inspector	Signature	Date signed
Virgil E. Lowe	Virgil E. Lowe	8-4-89
Address of Field Inspector (Street, city, state, ZIP code)		Phone number of Field Inspector
4009 Virginia Ave Muncie, IND, 47304		317-288-0708

### ABANDONMENT

Date abandonment completed and site inspected (Month, day, year)	
Abandonment requirements (check if completed)	
<input checked="" type="checkbox"/> Excavations filled <input checked="" type="checkbox"/> Equipment and debris removed <input checked="" type="checkbox"/> Top 3 feet of casing removed <input checked="" type="checkbox"/> Site leveled	
NOTE: Appropriate "Assumption of Responsibility" form(s) must be attached for any box(es) left unchecked above.	
I certify that this well has been abandoned in accordance with provisions of IC 13-4-7 and 310 IAC 7-1.	
Signature of Field Inspector	Date signed
Virgil E. Lowe	8-18-89



# WELL COMPLETION/ RE-COMPLETION REPORT

Form No. R3 (Formerly Form No. R4-8-1991)  
Revised on 8/16/1999

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055  
FAX (317) 232-1550  
Internet: <http://www.state.in.us/dnroil>

### Purpose of report

☒ Completion ☐ Re-completion ☐ Conversion

☒ Check here if you want the completion information to remain confidential for 1 year.

### FOR STATE USE ONLY

Date filed

Date released

## PART I

### GENERAL INFORMATION

Name of operator Opus Oil Properties, LLC	Telephone number (317)819-1878	Permit number 52947
Address of operator ( <input type="checkbox"/> Check here if this is a new address ) 841 Alverna Drive		
City Indianapolis	State IN	Zip code 46260

## PART II

### LOCATION INFORMATION

Name of lease Eric & Angela Bentz						Well number 1	Elevation (G.L.) 1135
Section 31	Township 20N	Range 15E	1/4 NE	1/4 SE	1/4 NE	Footage's: 330 ft. from <input checked="" type="checkbox"/> N, <input type="checkbox"/> S, <input type="checkbox"/> NW, <input type="checkbox"/> SE line 165 ft. from <input checked="" type="checkbox"/> E, <input type="checkbox"/> W, <input type="checkbox"/> NE, <input type="checkbox"/> SW line	
County Randolph	Distance to the nearest well capable of producing from the same formation 3800 ft. Note: This information is only required for Oil, Gas and Dual completion wells.						

## PART III

### WELL CONSTRUCTION

NOTE: This information is not required for Geologic/ structure test wells or Individual/ county test holes

Casing Specifications			Cement (In Sacks or Cubic Feet)				Hole	
Casing size O.D. (Inches)	Wt./ ft. ( lbs. ) - Grade	Setting depth	Stage 1 Volume	Stage 1 Class- yield per sack	Stage 2 or total volume if 1 stage	Stage 2 or total Class- yield per sack	Depth	Diameter (Inches)
Surface 8.62	lbs. - N/A	102 ft.	2.5 44	Class A - 22.00 1.18		-	100 ft.	12.25
Intermed. 6.62	lbs. - N/A	543 ft.	2.5 55	Class A - 22.00 1.18		-	545 ft.	8.0 7.875
Long str.	lbs. -	ft.					ft.	
Tubing	lbs. -	ft.						

Packer setting depth _____ ft.	Centralizers at _____ ft. _____ ft. _____ ft. _____ ft.	NOTE: For Class II Enhanced recovery and Saltwater disposal wells the well construction information must match the specifications of the written permit. If the information is different you must submit form no. A7 to request a modification of the existing permit conditions.
Packer setting depth _____ ft.		
Packer setting depth _____ ft.		
Casing perforated From _____ ft. to _____ ft.		
	From _____ ft. to _____ ft.	
	From _____ ft. to _____ ft.	
	From _____ ft. to _____ ft.	

## PART IV

### COMPLETION INFORMATION

Completion type ( Check one only )		
<input type="checkbox"/> Dry hole	<input type="checkbox"/> Gas storage/ observation well	<input type="checkbox"/> Enhanced recovery Class II well
<input type="checkbox"/> Oil well	<input type="checkbox"/> Geologic/ structure test well	<input type="checkbox"/> Dual completion Oil/ Class II well
<input checked="" type="checkbox"/> Gas well	<input type="checkbox"/> Non potable water supply well	<input type="checkbox"/> Dual completion Gas/ Class II well
<input type="checkbox"/> Non commercial gas well	<input type="checkbox"/> Saltwater disposal Class II well	
Date (Enter one only)	Tools	Total Depths
Completed 8/9/2006		Drillers 1175 ft
Re-completed	Rotary from 0 ft. to 1175 ft	Loggers 1175 ft.
Converted	Cable from _____ ft. to _____ ft.	


IMPORTANT: THIS FORM MUST BE SUBMITTED WITHIN 30 DAYS AFTER THE WELL COMPLETION OR RE-COMPLETION

Continued on next page

Apex K. Strunk 12/13/06

PART IV Cont'd.		COMPLETION INFORMATION						
Geophysical Logs		Completion Intervals		Well Treatments				
(Submit 3 copies of each)		From	ft. to	ft	Frac. with	gallons	Frac. with	lbs. sand
(CDL) COMPENSATED DENSITY POROSITY		From	ft. to	ft	Frac. with	gallons	Frac. with	lbs. sand
(CNL) COMPENSATED NEUTRON POROSITY		From	ft. to	ft	Acidized with gallons			
(ML) MICROLOG-MINILOG		From	ft. to	ft	Acidized with gallons			
(DIL) DUAL INDUCTION		From 1140 ft. to 1160 ft			Shot with 80 quarts			
Producing formation		Initial production (First 24 hours)						
Name Trenton Limestone		Oil		barrels	Gas 5 MCF			

[illegible]

<b>PART VII. AFFIRMATION</b>	
I affirm under penalty of perjury that the information provided in this report is true to the best of my knowledge and belief.	
Signature of operator or authorized agent	Date signed
	12/12/06
<b>Special Requirements</b>	

## NOTICE

Pursuant to IC 14-37-7-2 and 312 IAC 16-5-17, all data associated with the permit number identified below, is being retained in the confidential records of the Division of Oil and Gas. Access to any portion of these records is permissible after: a written, and signed release statement from the operator is submitted to the division; or, the twelve (12) month confidentiality period expires. Presently, this data is scheduled to be released by the Division of Oil and Gas on:

August 9, 2007

Operator	Opus Oil Properties, LLC					Permit:	52947
Farm Name	Eric & Angela Bentz					Well #	1
31	Sec.	Twp.	20N	Rge.	15E	County	Randolph

\_\_\_\_\_  
James B. AmRhein

Assistant Director  
Division of Oil and Gas

Date: 1/3/2007  
\_\_\_\_\_

**INFORMATION RELEASED**

DATE 15-Jan-08

BY [Signature]



# APPLICATION FOR TEMPORARY ABANDONMENT or PLUGGING DEFERRAL

Form No. A3  
Revised on 3/16/2006

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

### FOR STATE USE ONLY

Date received:

6-21-10

Date approved:

6-23-10

Approved by:

J. Amrhein

Valid thru:

6-8-2015

### PART I GENERAL INFORMATION

Name of Operator:

Opus Oil Properties, LLC

Telephone number:

(317) 819 - 1878

Permit number:

52947

Address of Operator:

280 E. 96<sup>th</sup> St, Ste 160, Indianapolis IN 46240

Type of submission (Check only one)

☐ Plugging Deferral until \_\_\_\_\_

☐ TA New

XX

☐ TA Renewal

### PART II WELL AND LEASE INFORMATION

Name of lease:

Eric and Angela Bentz

Well number:

1

County:

Randolph

Township:

20 N

Range:

15 E

Section:

31

1/4:

NE

1/4:

SE

1/4:

NE

Footage's: 330 ft. from ☐ N, ☐ S, ☐ NW, ☐ SE line

165 ft. from ☐ E, ☐ W, ☐ NE, ☐ SW line

Well Type (Check only one):

☐ Oil

X ☐ Gas

☐ Disposal

☐ Enhanced Recovery

☐ Other, specify: \_\_\_\_\_

Date well drilled:

8/9/2006 completed

Depth of surface casing:

543 ft.

Is surface casing cemented to surface?: X ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Is well equipped with: Long string cemented to surface? ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Intermediate or coal protection string cemented to surface? X ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Select all that apply: Well is equipped with ☐ Rods and Tubing ☐ Tubing and Packer ☐ Tubing with no Packer

☐ Packer set at \_\_\_\_\_ depth ☐ No Tubing ☐ Bridge plug at \_\_\_\_\_ depth ☐ Other: \_\_\_\_\_

Is the well equipped with a wellhead, stuffing-box assembly, or other fittings or valves capable of providing long-term containment of any wellbore fluids? X ☐ Yes ☐ No If No, describe modifications that will be made to ensure that all wellbore fluids will be contained within the well and not released into the environment during the period of Temporary Abandonment: \_\_\_\_\_

Is well currently active?: ☐ Yes

☒ No

If No, date well became inactive: 8/9/06

Is a copy of the FLUID LEVEL TEST REPORT or the results of the most recent MIT for the well attached with this application?

☐ Yes ☐ No NOTE: A completed FLUID LEVEL/PRESSURE TEST REPORT, MIT or other demonstration of well integrity must be submitted before this application can be approved

NOTE: WELL IS NEW, HAS LITTLE/NO FLUIDS, HAS NEVER PRODUCED AND HAS LOW PRESSURE & YIELD WITH CIRCULATED CEMENT

### PART III PURPOSE OF TA REQUEST

The following information is required for all Temporary Abandonment requests: (Attach additional sheets if needed)  
Skip to Part IV if requesting Plugging Deferral

A. Reason for requesting Temporary Abandonment: Well is being evaluated as part of a larger project for additional completion techniques and flow rate testing prior to installation of gathering lines, processing equipment, etc.

B. Improvements or workovers required (if any): Additional stimulations may be used, and/or well deepening

C. Time schedule for returning well to production: Well is new and has never been produced. Timetable for production is subject to many pending project details. TA is requested for 5 years until June 2015

**PART IV**

**AFFIRMATION**

I affirm under penalty of perjury that the information provided in this form is true to the best of my knowledge and belief.

Signature of operator or authorized agent

Date signed

June 7, 2010

**FOR DIVISION USE ONLY**

**Inspection checklist:**

☒ Surface sealed ☒ Pits filled ☒ PID posted ☒ Unrelated equipment removed ☒ Demonstration made

**Recommendation:**

☒ Approve as Requested ☐ Deny ☐ Approve with conditions: \_\_\_\_\_

Inspector:

Date:

6-8-10

**INSTRUCTIONS**

**PART I GENERAL INFORMATION**

- Enter the name of the operator exactly as it appears on the Organizational Report
- If a previously approved TA request has expired, or will be expiring in the near future, select "Renewal". Otherwise select "New".

**PART II WELL AND LEASE INFORMATION**

- Provide all of the information requested to identify the current well condition. This is important to assess the relative risks the well may pose to release production fluids into the environment or to contaminate USDW's.
- A completed WELL FLUID LEVEL/PRESSURE TEST REPORT or the results of the most recent MIT must be attached to this application or submitted before this application is approved.

**PART III PURPOSE OF REQUEST**

- A - Provide a detailed explanation of the reason for requesting TA for this well. Typical reasons include a lack of infrastructure development, contractual barriers, time to conduct detailed engineering/geologic evaluations, or the need to perform extensive workover or recompletion operations before operations resume.
- B - A complete description should be provided of all improvements or workovers that will be required, if any, before returning the well to production. The list should be specific and address any improvements needed to oil/water separation equipment, crude oil storage tanks, flow lines, secondary containment, produced water storage vessels, water injection facilities, access roads, and any completion/workover work that will be required during the period of TA.
- C - Provide a timetable for completing the steps identified in B above including dates by which the activities are intended to be completed and the date the well is expected to be returned to active production.

**PART IV AFFIRMATION**

- The TA request must be signed by the operator or authorized representative to affirm that all of the information provided in this form is true to the best of their knowledge and belief.

**NOTE: SUBMIT COMPLETED APPLICATION TO INSPECTOR**



## FLUID LEVEL/PRESSURE TEST REPORT

Form No. R6  
Revised on 3/16/2006

### INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

### FOR DIVISION USE ONLY

#### Fluid Depth Calculation

Surface elevation \_\_\_\_\_ ft.  
Minus USDW elevation \_\_\_\_\_ ft. (Plus if elevation is negative)  
Plus USDW factor 100 ft.  
=Minimum Fluid Depth \_\_\_\_\_ ft.

PART I GENERAL INFORMATION									
Name of operator Opus Oil Properties, LLC					Telephone number (317) 819 - 1878			Permit number 52947	
Name of lease Eric and Angela Bentz		Well number 1	County Randolph	Township 20 N	Range 15 E	Section 31	1/4 NE	1/4 SE	1/4 NE
Type of submission (Check one only) <input type="checkbox"/> First year plugging deferral <input type="checkbox"/> Fluid Level Test for TA'd well									

PART II AFFIRMATIONS	
I (we) affirm under penalty of perjury that the information provided in this form is true to the best of my (our) knowledge and belief.	
Signature of operator or authorized agent	Date signed 6/7/10
Signature of person certifying the fluid depth from an Echometer®	Date Signed
Signature of person certifying the tubing tally	Date Signed

PART III	
Fluid Level Test	
Measuring method: (Check one only) <input type="checkbox"/> Echometer® (Attach tape) <input type="checkbox"/> Wireline/ electronic probe <input type="checkbox"/> Other (Describe) _____	
Important: If the Echometer® box is checked, the person certifying fluid depth must sign above	
Test result: Fluid depth _____ ft. <input type="checkbox"/> Pass (Fluid Depth is > Minimum Fluid Depth) <input type="checkbox"/> Fail (Fluid Depth is < Minimum Fluid Depth)	
Section b Pressure Test	
Test information: Plug/ packer depth * ft. Top of upper perms. _____ ft. Start pressure 195 psi End pressure 195 psi	Plug/ packer depth verified by: (Check one only) <input type="checkbox"/> Inspectors visual tally <input type="checkbox"/> Tubing tally <input type="checkbox"/> Witnessed wireline Important: If the tubing tally box is checked, the person certifying the tally must sign above
Test result: <input checked="" type="checkbox"/> Pass <input type="checkbox"/> Fail	
Inspector: J. Culbert	Date: 6-8-10 Did Inspector witness this test? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No

#### SPECIAL REQUIREMENTS

1. The applicant is responsible for notifying the inspector at least 48 hours in advance prior to conducting the well demonstration. The inspector is not required to witness each well demonstration.
2. If the well fails the fluid level check you must perform a standard pressure test to retain the well on TA status.

\* - on 6-7-10 the well had a starting static gas pressure of 195 psi. The well was bled down to 175 psi.

- on 6-8-10 I returned to the well & the pressure was back up to 195 psi.



## TEMPORARY ABANDONMENT AUTHORIZATION

Form No. P1

Revised 1/15/2002

INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 W. Washington St., Rm. 293

Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet - <http://www.in.gov/dnroil>

Opus Oil Properties LLC

280 E. 96th Street, Suite 160

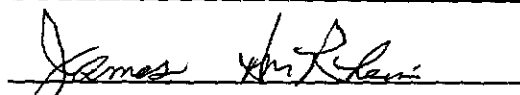
Indianapolis IN 46240-

is hereby authorized to temporarily abandon the following well:

Permit No.	Well No.	Lease Name	Township Range	Section	Quarters
52947	1	Bentz	20 N 15 E	31	ne se ne

This authorization is valid until **6/8/2015** under the following conditions:

1. An intact, leak free wellhead or cap with a valve configured to monitor casing or casing-tubing annulus pressure is maintained on the well.
2. The well site is kept free of unnecessary equipment, vegetation, and debris
3. Well identification is posted and maintained per 312 IAC 16-5-10
4. A bond is maintained on the well as required per 312 IAC 16-5
5. The well is not operated
6. The well does not threaten an underground source of drinking water.
7. If a fluid level check was used to demonstrate well integrity you must perform a fluid level check no later than **6/23/2011** and annually thereafter until this authorization expires.

  
FOR THE DIVISION OF OIL AND GAS

### IMPORTANT

If this well is a Class II well, the issuance of this Temporary Abandonment authorization voids the injection authorization for this well and you **MUST** obtain a new injection authorization letter before injecting into this well.

Renewal of temporary abandonment status will only be granted if you have submitted a renewal justification with adequate supporting documentation and the well passes a demonstration per 312 IAC 16-5-19(d).

If you place the well in operation or to obtain further information about the requirements of this temporary abandonment permit you should contact oil and gas inspector jwhite



# APPLICATION FOR TEMPORARY ABANDONMENT or PLUGGING DEFERRAL

Form No. A3  
Revised on 3/16/2006

INDIANA DEPARTMENT OF NATURAL RESOURCES  
Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

## FOR STATE USE ONLY

Date received:

5-7-07

Date approved:

5-15-07

Approved by:

Jim Anderson  
per HLM

Valid thru:

6-7-2010

### PART I

### GENERAL INFORMATION

Name of Operator:

Opus Oil Properties, LLC

Telephone number:

(317) 819 - 1878

Permit number:

52947

Address of Operator:

841 Alverna Drive, Indianapolis, IN 46260

Type of submission (Check only one)

☐ Plugging Deferral until \_\_\_\_\_

☒ TA New

☐ TA Renewal

### PART II

### WELL AND LEASE INFORMATION

Name of lease:

Eric and Angela Bentz

Well number:

1

County:

Randolph

Township:

20 N

Range:

15 E

Section:

31

1/4:

NE

1/4:

SE

1/4:

NE

Footage's: 330 ft. from ☐ N, ☐ S, ☐ NW, ☐ SE line

165 ft. from ☐ E, ☐ W, ☐ NE, ☐ SW line

Well Type (Check only one):

☐ Oil

☒ Gas

☐ Disposal

☐ Enhanced Recovery

☐ Other, specify: \_\_\_\_\_

Date well drilled:

8/9/2006 completed

Depth of surface casing:

543 ft.

Is surface casing cemented to surface?: ☒ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Is well equipped with: Long string cemented to surface? ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Intermediate or coal protection string cemented to surface? ☒ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Select all that apply: Well is equipped with ☐ Rods and Tubing ☐ Tubing and Packer ☐ Tubing with no Packer

☐ Packer set at \_\_\_\_\_ depth ☐ No Tubing ☐ Bridge plug at \_\_\_\_\_ depth ☐ Other: \_\_\_\_\_

Is the well equipped with a wellhead, stuffing-box assembly, or other fittings or valves capable of providing long-term containment of any wellbore fluids? ☒ Yes ☐ No If No, describe modifications that will be made to ensure that all wellbore fluids will be contained within the well and not released into the environment during the period of Temporary Abandonment: \_\_\_\_\_

Is well currently active?: ☐ Yes ☐ No If No, date well became inactive: 8/9/06

Is a copy of the FLUID LEVEL TEST REPORT or the results of the most recent MIT for the well attached with this application?

☐ Yes ☐ No NOTE: A completed FLUID LEVEL/PRESSURE TEST REPORT, MIT or other demonstration of well integrity must be submitted before this application can be approved

NOTE: WELL IS NEW, HAS LITTLE/NO FLUIDS, HAS NEVER PRODUCED AND HAS LOW PRESSURE & YIELD WITH CIRCULATED CEMENT

### PART III

### PURPOSE OF TA REQUEST

The following information is required for all Temporary Abandonment requests: (Attach additional sheets if needed)

Skip to Part IV if requesting Plugging Deferral

A. Reason for requesting Temporary Abandonment: Well is being evaluated as part of a larger project for additional completion techniques and flow rate testing prior to installation of gathering lines, processing equipment, etc

B. Improvements or workovers required (if any): Additional stimulations may be used, and/or well deepening

C. Time schedule for returning well to production: Well is new and has never been produced. Timetable for production is subject to additional work in 2007, and possible production in 2008 pending many project details. TA is requested for 3 years until June 2010

**PART IV**

**AFFIRMATION**

I affirm under penalty of perjury that the information provided in this form is true to the best of my knowledge and belief.

Signature of operator or authorized agent

Date signed

May 4, 2007

**FOR DIVISION USE ONLY**

**Inspection checklist:**

☒ Surface sealed ☒ Pits filled ☒ ID posted ☒ Unrelated equipment removed ☐ Demonstration made

**Recommendation:**

☐ Approve as Requested ☐ Deny ☐ Approve with conditions: \_\_\_\_\_

Inspector: [Signature]

Date: 5-29-07

**INSTRUCTIONS**

**PART I GENERAL INFORMATION**

- Enter the name of the operator exactly as it appears on the Organizational Report
- If a previously approved TA request has expired, or will be expiring in the near future, select "Renewal". Otherwise select "New".

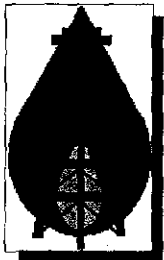
**PART II WELL AND LEASE INFORMATION**

- Provide all of the information requested to identify the current well condition. This is important to assess the relative risks the well may pose to release production fluids into the environment or to contaminate USDW's.
- A completed WELL FLUID LEVEL/PRESSURE TEST REPORT or the results of the most recent MIT must be attached to this application or submitted before this application is approved.

**PART III PURPOSE OF REQUEST**

- A - Provide a detailed explanation of the reason for requesting TA for this well. Typical reasons include a lack of infrastructure development, contractual barriers, time to conduct detailed engineering/geologic evaluations, or the need to perform extensive workover or recompletion operations before operations resume.
- B - A complete description should be provided of all improvements or workovers that will be required, if any, before returning the well to production. The list should be specific and address any improvements needed to oil/water separation equipment, crude oil storage tanks, flow lines, secondary containment, produced water storage vessels, water injection facilities, access roads, and any completion/workover work that will be required during the period of TA.
- C - Provide a timetable for completing the steps identified in B above including dates by which the activities are intended to be completed and the date the well is expected to be returned to active production.

**PART IV AFFIRMATION**



## TEMPORARY ABANDONMENT AUTHORIZATION

Form No. P1

Revised 1/15/2002

### INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 W. Washington St., Rm. 293

Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet - <http://www.in.gov/dnroil>

Opus Oil Properties LLC

841 Alverna Drive

Indianapolis IN 46260-

is hereby authorized to temporarily abandon the following well

Permit No.	Well No.	Lease Name	Township Range	Section	Quarters
52947	1	Bentz	20 N 15 E	31	ne se ne

This authorization is valid until 6/1/2010 under the following conditions:

1. An intact, leak free wellhead or cap with a valve configured to monitor casing or casing-tubing annulus pressure is maintained on the well.
2. The well site is kept free of unnecessary equipment, vegetation, and debris
3. Well identification is posted and maintained per 312 IAC 16-5-10
4. A bond is maintained on the well as required per 312 IAC 16-5
5. The well is not operated
6. The well does not threaten an underground source of drinking water.

Jim AmRhein, Assistant Director  
Oil and Gas Division

### IMPORTANT

If this well is a Class II well, the issuance of this Temporary Abandonment authorization voids the injection authorization for this well and you **MUST** obtain a new injection authorization letter before injecting into this well.

Renewal of temporary abandonment status will only be granted if you have submitted a renewal justification with adequate supporting documentation and the well passes a demonstration per 312 IAC 16-5-19(d).

If you place the well in operation or to obtain further information about the requirements of this temporary abandonment permit you should contact oil and gas inspector jwhite



# WELL COMPLETION/ RE-COMPLETION REPORT

Form No. R3 (Formerly Form No. R4-8-1991)  
Revised on 8/16/1999

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet: <http://www.state.in.us/dnroil>

### Purpose of report

☒ Completion ☐ Re-completion ☐ Conversion

☒ Check here if you want the completion information to remain confidential for 1 year.

### FOR STATE USE ONLY

Date filed

Date released

### PART I

### GENERAL INFORMATION

Name of operator Opus Oil Properties, LLC	Telephone number (317)819-1878	Permit number 53133 53113
Address of operator ( <input type="checkbox"/> Check here if this is a new address ) 841 Alverna Drive		
City Indianapolis	State IN	Zip code 46260

### PART II

### LOCATION INFORMATION

Name of lease Mabel Thornburg					Well number 1: LOST		Elevation (G.L.) 1133
Section 29	Township 20N	Range 15E	1/4 SE	1/4 SW	Footage's: 165 ft. from <input type="checkbox"/> N, <input checked="" type="checkbox"/> S, <input type="checkbox"/> NW, <input type="checkbox"/> SE line 661 ft. from <input checked="" type="checkbox"/> E, <input type="checkbox"/> W, <input type="checkbox"/> NE, <input type="checkbox"/> SW line		
County Randolph		Distance to the nearest well capable of producing from the same formation 1100 ft. Note: This information is only required for Oil, Gas and Dual completion wells.					

### PART III

### WELL CONSTRUCTION

NOTE: This information is not required for Geologic/ structure test wells or Individual/ county test holes

Casing Specifications			Cement (In Sacks or Cubic Feet)				Hole	
Casing size O.D. (Inches)	Wt./ ft. ( lbs. ) - Grade	Setting depth	Stage 1 Volume	Stage 1 Class- yield per sack	Stage 2 or total volume if 1 stage	Stage 2 or total Class- yield per sack	Depth	Diameter (Inches)
Surface 8.62	NEW lbs. - N/A	122 ft.	55 SX	Class A -1.18		-	122 ft.	12.25
Intermed. N/A	NEW lbs. - N/A	ft.		-		-	ft.	
Long str.	lbs. -	ft.		-		-	ft.	
Tubing	lbs. -	ft.						

Packer setting depth ____ ft. Packer setting depth ____ ft. Packer setting depth ____ ft.	Centralizers at ____ ft. ____ ft. ____ ft. ____ ft.  Casing perforated From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft.	NOTE: For Class II Enhanced recovery and Saltwater disposal wells the well construction information must match the specifications of the written permit. If the information is different you must submit form no. A7 to request a modification of the existing permit conditions.
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### PART IV

### COMPLETION INFORMATION

Completion type ( Check one only )		
<input checked="" type="checkbox"/> Dry hole <input type="checkbox"/> Oil well <input type="checkbox"/> Gas well <input type="checkbox"/> Non commercial gas well	<input type="checkbox"/> Gas storage/ observation well <input type="checkbox"/> Geologic/ structure test well <input type="checkbox"/> Non potable water supply well <input type="checkbox"/> Saltwater disposal Class II well	<input type="checkbox"/> Enhanced recovery Class II well <input type="checkbox"/> Dual completion Oil/ Class II well <input type="checkbox"/> Dual completion Gas/ Class II well <input checked="" type="checkbox"/> Water well Conversion
Date (Enter one only) Completed 12/5/2006 Re-completed Converted	Tools Rotary from 0 ft. to 500 ft Cable from ____ ft. to ____ ft.	Total Depths Drillers 500 ft Loggers ____ ft.

Continued on next page

### COMPLETION INFORMATION

## PART V

## OIL AND GAS OCCURRENCES

## PART VI

## FORMATION INFORMATION

**PART 4**

### AFFIRMATION

I affirm under penalty of perjury that the information provided in this report is true to the best of my knowledge and belief.

Date signed \_\_\_\_\_

### Special Requirements

1. Only those persons whose names appear in PARTS V or VI of the Organizational Report are authorized to sign this report.
2. **If this is a directional or horizontal well you must submit a copy of the directional survey with this report.**
3. **You must submit 3 copies of ALL geophysical logs run on this well.**



## RECORD OF WATER WELL

State Form 35680 (R5 / 9-04)

Driller--Mail complete record in 30 days to:  
INDIANA DEPT. OF NATURAL RESOURCES  
Division of Water  
402 W. Washington St., Rm. W264  
Indianapolis, IN 46204-2641  
(877) 928-3755 toll-free or (317) 232-4160

County Permit

Number

DNR Variance

Number

Include if applicable

Fill in completely

## WELL LOCATION

County where drilled <u>Randolph</u>	Civil township name <u>T20N</u>	Township number (N-S) <u>R15E</u>	Range number (E-W) <u>29</u>
Driving directions to the well location (include trip origin, street & road names, intersecting roads, and compass directions). Show well address below and subdivision in box at lower right. There is space for a map on the reverse side. <u>Staked Location</u> <u>1005 East of 500E</u> <u>Sec 29 T20N R15E SE/SW</u> <u>165' from South Line</u> <u>661' from East Line</u>			
Well address: <u>591 Huron Dr Indianapolis 46260</u> → <u>5200 E/100 S</u>			

If drilled for water supply, this well is: ☐ First well on property ☐ Replacement well ☐ Additional well on property ☐ Dry hole

## OWNER - CONTRACTOR

Well owner-name <u>Opus Oil transferred to Mabel Thornburg Life &amp; Estate</u>	Telephone number <u>964 6184</u>
Address (number and street, city, state, ZIP code) <u>591 Huron Dr Indianapolis 46260</u> → <u>5200 E/100 S</u>	
Building contractor-name <u>R&amp;S Drilling</u>	Address (number and street, city, state, ZIP code) <u>40 Bill Thornburg (765) 964 6184</u>
Drilling contractor-name <u>Jack Racer (765) 748 0886</u>	Address (number and street, city, state, ZIP code) <u>40 Bill Thornburg (765) 964 6184</u>
Equipment operator-name <u>Jack Racer (765) 748 0886</u>	License number of operator <u>12/5/06</u>

## CONSTRUCTION DETAILS

Use of well <input type="checkbox"/> Home <input type="checkbox"/> Public supply <input type="checkbox"/> Industrial / commercial <input type="checkbox"/> Livestock <input type="checkbox"/> Irrigation <input type="checkbox"/> Monitoring / environ. <input type="checkbox"/> Test hole Other: _____	Drilling method <input type="checkbox"/> Rotary <input type="checkbox"/> Reverse rotary <input type="checkbox"/> Cable tool <input type="checkbox"/> Jet <input type="checkbox"/> Bucket / bore <input type="checkbox"/> Auger (including HSA) <input type="checkbox"/> Direct push Other: _____	Type of pump <input type="checkbox"/> Submersible <input type="checkbox"/> Shallow-well jet <input type="checkbox"/> Deep-well jet <input type="checkbox"/> No pump installed Other: _____ Pump depth setting (feet) _____
Total depth of well (feet) <u>500</u>	Borehole diameter (in.) <u>2.25</u>	Gravel pack inserted <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
Casing length (feet) <u>122</u>	Casing diameter (in.) <u>8.0</u>	Casing material <input type="checkbox"/> PVC <input checked="" type="checkbox"/> Steel
Screen length (feet) <u>—</u>	Screen diameter (in.) <u>—</u>	Screen material <input type="checkbox"/> PVC <input checked="" type="checkbox"/> Steel
Screen slot size <u>—</u>	Water quality (clear, odor, etc.) <u>clear + Fresh</u>	

## WELL LOG

FORMATIONS: Type of material	From (feet)	To (feet)
<u>Glacial</u>	<u>0</u>	<u>110</u>
<u>Silurian limestone</u>	<u>110</u>	<u>320</u>
<u>Magnesian Gyps</u>	<u>320</u>	<u>500</u>

well drilled as gas exploration test - abandoned due to crooked hole

## WELL CAPACITY TEST

Test method <input type="checkbox"/> Air <input type="checkbox"/> Bailing <input type="checkbox"/> Pumping	Static level below surface <u>?</u> feet	Gallons per min. <u>?</u>	Hours tested <u>?</u>	Drawdown (change in level) <u>?</u> feet
---	---	------------------------------	--------------------------	---

## GROUTING

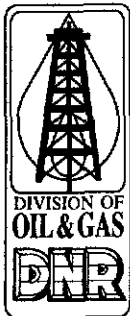
## WELL ABANDONMENT

Grout material <u>Imz Cement</u>	Grout depth from to <u>0</u> <u>122</u>	Sealing material <u>—</u>	Depth filled from to <u>—</u> <u>—</u>
Installation method <u>pumps</u>	No. of bags used <u>55 sacks</u>	Installation method <u>—</u>	No. of bags used <u>—</u>

Ground Elevation = 1133.40'  
Water 15 from limestone

See Geophysical logs on  
Red with Oil & Gas Division

I hereby swear or affirm, under the penalties for perjury, that the information submitted herewith is, to the best of my knowledge and belief, true, accurate, and complete.	Signature of drilling contractor or authorized representative <u>Kevin [Signature]</u>	MUST BE SIGNED OR STAMPED <u>Agent Opus Oil</u>	Date <u>9/10/08</u>
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# APPLICATION FOR ASSUMPTION OF RESPONSIBILITY

Form No. A6  
Revised on 5/3/07

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055  
FAX (317) 232-1550  
Internet: <http://www.state.in.us/dnroil>

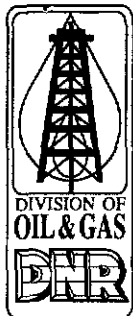
53113

Permit Number <del>52133</del>	Section 29	Township 20N	Range 15E
Name of lease Mabel Thornburg L.E.			Well Number #1

<b>I certify that I am the owner of land on which a facility regulated under IC 14-37 was located. At my request, the following items were left for my personal use.</b>			
<input checked="" type="checkbox"/> Well (As a water well) @ plugback depth of 500 ft.	<input type="checkbox"/> Excavations	<input type="checkbox"/> Equipment	<input type="checkbox"/> Surface casing
<b>I hereby state that I will not use the well or excavations for oil and gas purposes as defined by IC 14-37 without prior approval from the Division of Oil and Gas.</b>			
<b>We affirm under the penalty for perjury that the foregoing is true to the best of our knowledge and belief.</b>			
Signature of operator <i>Tim Stark</i>		Date signed 5/11/07	
Signature of landowner <i>William H. Thornburg</i>		Date signed 5/4/2007	
<b>PART II DIVISION APPROVAL</b>			
Signature of inspector <i>[Signature]</i>		Date signed 05-28-07	

### SPECIAL REQUIREMENTS

1. This form **must** accompany the Plugging and Abandonment Report if all of the boxes in the site Certification section of that report are not checked.
2. Only those persons whose names appear in PARTS V or VI of the Organizational Report may sign this form as the operator
3. The signatures of the operator, landowner, and inspector **must** appear on this form before the assumption of responsibility will be accepted
4. If the landowner is accepting responsibility for a well it **must** be plugged back to a depth that is no deeper than the bottom of the lowest Underground Source of Drinking Water.



# WELL COMPLETION/ RE-COMPLETION REPORT

Form No. R3 (Formerly Form No. R4-8-1991)  
Revised on 8/16/1999

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055  
FAX (317) 232-1550  
Internet: <http://www.state.in.us/dnroil>

*Cement ok*  
*APA 3 July 06*

### Purpose of report

☒ Completion ☐ Re-completion ☐ Conversion

☒ Check here if you want the completion information to remain confidential for 1 year.

### FOR STATE USE ONLY

Date filed

Date released

### PART I

### GENERAL INFORMATION

Name of operator Opus Oil Properties, LLC	Telephone number (317)819-1878	Permit number 53114
Address of operator ( <input type="checkbox"/> Check here if this is a new address ) 841 Alverna Drive		
City Indianapolis	State IN	Zip code 46260

### PART II

### LOCATION INFORMATION

Name of lease Noel Carpenter						Well number 1	Elevation (G.L.) 1106
Section 17	Township 20N	Range 15E	1/4 SW	1/4 SW	1/4 SW	Footage's: 340 ft. from <input type="checkbox"/> N, <input checked="" type="checkbox"/> S, <input type="checkbox"/> NW, <input type="checkbox"/> SE line 185 ft. from <input type="checkbox"/> E, <input checked="" type="checkbox"/> W, <input type="checkbox"/> NE, <input type="checkbox"/> SW line	
County Randolph	Distance to the nearest well capable of producing from the same formation 3100 ft. Note: This information is only required for Oil, Gas and Dual completion wells.						

### PART III

### WELL CONSTRUCTION

NOTE: This information is not required for Geologic/ structure test wells or Individual/ county test holes

Casing Specifications			Cement (In Sacks or Cubic Feet)				Hole	
Casing size O.D. (Inches)	Wt./ ft. ( lbs. ) - Grade	Setting depth	Stage 1 Volume	Stage 1 Class- yield per sack	Stage 2 or total volume if 1 stage	Stage 2 or total Class- yield per sack	Depth	Diameter (Inches)
Surface 8.62	new lbs. -N/A	115 ft.	55 SX	Class A -1.18		-	115 ft.	12.25
Intermed. 6.62	new lbs. -N/A	495 ft.	55 sx	Class A -1.18		-	495 ft.	7.88
Long str.	lbs. -	ft.		-		-	1166 ft.	6.00
Tubing	lbs. -	ft.						

Packer setting depth ____ ft. Packer setting depth ____ ft. Packer setting depth ____ ft.	Centralizers at ____ ft. ____ ft. ____ ft. ____ ft.  Casing perforated From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft.	NOTE: For Class II Enhanced recovery and Saltwater disposal wells the well construction information must match the specifications of the written permit. If the information is different you must submit form no. A7 to request a modification of the existing permit conditions.
---	---	---

### PART IV

### COMPLETION INFORMATION

Completion type ( Check one only )		
<input type="checkbox"/> Dry hole <input type="checkbox"/> Oil well <input checked="" type="checkbox"/> Gas well <input type="checkbox"/> Non commercial gas well	<input type="checkbox"/> Gas storage/ observation well <input type="checkbox"/> Geologic/ structure test well <input type="checkbox"/> Non potable water supply well <input type="checkbox"/> Saltwater disposal Class II well	<input type="checkbox"/> Enhanced recovery Class II well <input type="checkbox"/> Dual completion Oil/ Class II well <input type="checkbox"/> Dual completion Gas/ Class II well
Date (Enter one only) Completed 11/22/2006 Re-completed Converted	Tools Rotary from 0 ft. to 1166 ft Cable from ____ ft. to ____ ft.	Total Depths Drillers 1166 ft Loggers 1168 ft.

Continued on next page

## COMPLETION INFORMATION

## PART IV

## OIL AND GAS OCCURRENCES

## PART IV

### FORMATION INFORMATION

## PART VII

## AFFIRMATION

Signature of operator or authorized agent

Date signed

### Special Requirements

1. Only those persons whose names appear in PARTS V or VI of the Organizational Report are authorized to sign this report.
2. **If this is a directional or horizontal well you must submit a copy of the directional survey with this report.**
3. **You must submit 3 copies of ALL geophysical logs run on this well.**



# APPLICATION FOR TEMPORARY ABANDONMENT or PLUGGING DEFERRAL

Form No. A3  
Revised on 3/16/2006

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

### FOR STATE USE ONLY

Date received:

5-7-07

Date approved:

5-15-07

Approved by:

*Jim Anderson*  
*per HCM*

Valid thru:

6-1-2010

### PART I

### GENERAL INFORMATION

Name of Operator:

Opus Oil Properties, LLC

Telephone number:

(317) 819 - 1878

Permit number:

53114

Address of Operator:

841 Alverna Drive, Indianapolis, IN 46260

Type of submission (Check only one)

☐ Plugging Deferral until \_\_\_\_\_

☒ X TA New

☐ TA Renewal

### PART II

### WELL AND LEASE INFORMATION

Name of lease:

Noel Carpenter

Well number:

1

County:

Randolph

Township:

20 N

Range:

15 E

Section:

17

1/4:

SW

1/4:

SW

1/4:

SW

Footage's: 340 ft. from ☐ N, ☒ X ☐ S, ☐ NW, ☐ SE line

185 ft. from ☐ E, ☒ X ☐ W, ☐ NE, ☐ SW line

Well Type (Check only one):

☐ Oil

☒ X ☐ Gas

☐ Disposal

☐ Enhanced Recovery

☐ Other, specify: \_\_\_\_\_

Date well drilled:

11/22/2006 completed

Depth of surface casing:

495 ft.

Is surface casing cemented to surface?: ☒ X ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Is well equipped with: Long string cemented to surface? ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Intermediate or coal protection string cemented to surface? ☒ X ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Select all that apply: Well is equipped with ☐ Rods and Tubing ☐ Tubing and Packer ☐ Tubing with no Packer

☐ Packer set at \_\_\_\_\_ depth ☐ No Tubing ☐ Bridge plug at \_\_\_\_\_ depth ☐ Other: \_\_\_\_\_

Is the well equipped with a wellhead, stuffing-box assembly, or other fittings or valves capable of providing long-term containment of any wellbore fluids? ☒ X ☐ Yes ☐ No If No, describe modifications that will be made to ensure that all wellbore fluids will be contained within the well and not released into the environment during the period of Temporary Abandonment: \_\_\_\_\_

Is well currently active?: ☐ Yes ☐ No If No, date well became inactive: 8/9/06

Is a copy of the FLUID LEVEL TEST REPORT or the results of the most recent MIT for the well attached with this application?

☐ Yes ☐ No NOTE: A completed FLUID LEVEL/PRESSURE TEST REPORT, MIT or other demonstration of well integrity must be submitted before this application can be approved

NOTE: WELL IS NEW, HAS LITTLE/NO FLUIDS, HAS NEVER PRODUCED AND HAS LOW PRESSURE & YIELD WITH CIRCULATED CEMENT

### PART III

### PURPOSE OF TA REQUEST

The following information is required for all Temporary Abandonment requests: (Attach additional sheets if needed)

Skip to Part IV if requesting Plugging Deferral

A. Reason for requesting Temporary Abandonment: Well is being evaluated as part of a larger project for additional completion techniques and flow rate testing prior to installation of gathering lines, processing equipment, etc

B. Improvements or workovers required (if any): Additional stimulations may be used, and/or well deepening

C. Time schedule for returning well to production: Well is new and has never been produced. Timetable for production is subject to additional work in 2007, and possible production in 2008 pending many project details. TA is requested for 3 years until June 2010

**PART IV**

**AFFIRMATION**

I affirm under penalty of perjury that the information provided in this form is true to the best of my knowledge and belief.

Signature of operator or authorized agent

Date signed

May 4, 2007

**FOR DIVISION USE ONLY**

**Inspection checklist:**

☒ Surface sealed ☒ Pits filled ☒ ID posted ☒ Unrelated equipment removed ☐ Demonstration made

**Recommendation:**

☐ Approve as Requested ☐ Deny ☐ Approve with conditions: \_\_\_\_\_

Inspector:

Date:

5-28-07

**INSTRUCTIONS**

**PART I GENERAL INFORMATION**

- Enter the name of the operator exactly as it appears on the Organizational Report
- If a previously approved TA request has expired, or will be expiring in the near future, select "Renewal". Otherwise select "New".

**PART II WELL AND LEASE INFORMATION**

- Provide all of the information requested to identify the current well condition. This is important to assess the relative risks the well may pose to release production fluids into the environment or to contaminate USDW's.
- A completed WELL FLUID LEVEL/PRESSURE TEST REPORT or the results of the most recent MIT must be attached to this application or submitted before this application is approved.

**PART III PURPOSE OF REQUEST**

- A – Provide a detailed explanation of the reason for requesting TA for this well. Typical reasons include a lack of infrastructure development, contractual barriers, time to conduct detailed engineering/geologic evaluations, or the need to perform extensive workover or recompletion operations before operations resume.
- B – A complete description should be provided of all improvements or workovers that will be required, if any, before returning the well to production. The list should be specific and address any improvements needed to oil/water separation equipment, crude oil storage tanks, flow lines, secondary containment, produced water storage vessels, water injection facilities, access roads, and any completion/workover work that will be required during the period of TA.
- C – Provide a timetable for completing the steps identified in B above including dates by which the activities are intended to be completed and the date the well is expected to be returned to active production.

**PART IV AFFIRMATION**

- The TA request must be signed by the operator or authorized representative to affirm that all of the information provided in this form is true to the best of their knowledge and belief.

**NOTE: SUBMIT COMPLETED APPLICATION TO INSPECTOR**



## TEMPORARY ABANDONMENT AUTHORIZATION

Form No. P1

Revised 1/15/2002

INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 W. Washington St., Rm. 293

Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet - <http://www.in.gov/dnroil>

Opus Oil Properties LLC

841 Alverna Drive

Indianapolis IN 46260-


is hereby authorized to temporarily abandon the following well

Permit No.	Well No.	Lease Name	Township Range	Section	Quarters
53114	1	Noel Carpenter	20 N 15 E	17	SW SW SW

This authorization is valid until 6/1/2010 under the following conditions:

1. An intact, leak free wellhead or cap with a valve configured to monitor casing or casing-tubing annulus pressure is maintained on the well.
2. The well site is kept free of unnecessary equipment, vegetation, and debris
3. Well identification is posted and maintained per 312 IAC 16-5-10
4. A bond is maintained on the well as required per 312 IAC 16-5
5. The well is not operated
6. The well does not threaten an underground source of drinking water.

### IMPORTANT

  
Jim AmRhein, Assistant Director  
Oil and Gas Division

If this well is a Class II well, the issuance of this Temporary Abandonment authorization voids the injection authorization for this well and you **MUST** obtain a new injection authorization letter before injecting into this well.

Renewal of temporary abandonment status will only be granted if you have submitted a renewal justification with adequate supporting documentation and the well passes a demonstration per 312 IAC 16-5-19(d).

If you place the well in operation or to obtain further information about the requirements of this temporary abandonment permit you should contact oil and gas inspector jwhite



# APPLICATION FOR TEMPORARY ABANDONMENT or PLUGGING DEFERRAL

Form No. A3  
Revised on 3/16/2006

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

### FOR STATE USE ONLY

Date received:

6-21-10

Date approved:

6-23-10

Approved by:

J. Amick

Valid thru:

6-8-2015

### PART I

### GENERAL INFORMATION

Name of Operator:

Opus Oil Properties, LLC

Telephone number:

(317) 819 - 1878

Permit number:

53114

Address of Operator:

280 E. 96<sup>th</sup> St, Ste 160, Indianapolis IN 46240

Type of submission (Check only one) ☐ Plugging Deferral until ☐ TA New ☐ XX TA Renewal

### PART II

### WELL AND LEASE INFORMATION

Name of lease:

Noel Carpenter

Well number:

1

County:

Randolph

Township:

20 N

Range:

15 E

Section:

17

1/4:

SW

1/4:

SW

1/4:

SW

Footage's: 340 ft. from ☐ N, ☐ X ☐ S, ☐ NW, ☐ SE line  
185 ft. from ☐ E, ☐ X ☐ W, ☐ NE, ☐ SW line

Well Type (Check only one):

☐ Oil ☒ Gas ☐ Disposal ☐ Enhanced Recovery ☐ Other, specify:

Date well drilled:

11/22/2006 completed

Depth of surface casing:

495 ft.

Is surface casing cemented to surface?: ☒ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield:

Is well equipped with: Long string cemented to surface? ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield:

Intermediate or coal protection string cemented to surface? ☒ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield:

Select all that apply: Well is equipped with ☐ Rods and Tubing ☐ Tubing and Packer ☐ Tubing with no Packer

☐ Packer set at \_\_\_\_\_ depth ☐ No Tubing ☐ Bridge plug at \_\_\_\_\_ depth ☐ Other: \_\_\_\_\_

Is the well equipped with a wellhead, stuffing-box assembly, or other fittings or valves capable of providing long-term containment of any wellbore fluids? ☒ Yes ☐ No If No, describe modifications that will be made to ensure that all wellbore fluids will be contained within the well and not released into the environment during the period of Temporary Abandonment: \_\_\_\_\_

Is well currently active?: ☐ Yes ☒ No If No, date well became inactive: 8/9/06

Is a copy of the FLUID LEVEL TEST REPORT or the results of the most recent MIT for the well attached with this application?

☐ Yes ☐ No NOTE: A completed FLUID LEVEL/PRESSURE TEST REPORT, MIT or other demonstration of well integrity must be submitted before this application can be approved

NOTE: WELL IS NEW, HAS LITTLE/NO FLUIDS, HAS NEVER PRODUCED AND HAS LOW PRESSURE & YIELD WITH CIRCULATED CEMENT

### PART III

### PURPOSE OF TA REQUEST

The following information is required for all Temporary Abandonment requests: (Attach additional sheets if needed)  
Skip to Part IV if requesting Plugging Deferral

A. Reason for requesting Temporary Abandonment: Well is being evaluated as part of a larger project for additional completion techniques and flow rate testing prior to installation of gathering lines, processing equipment, etc.

B. Improvements or workovers required (if any): Additional stimulations may be used, and/or well deepening

C. Time schedule for returning well to production: Well is new and has never been produced. Timetable for production is subject to many pending project details. TA is requested for 5 years until June 2015.

**PART IV**

**AFFIRMATION**

I affirm under penalty of perjury that the information provided in this form is true to the best of my knowledge and belief.

Signature of operator or authorized agent: 

Date signed  
June 7, 2010

**FOR DIVISION USE ONLY**

**Inspection checklist:**

☒ Surface sealed ☒ Pits filled ☒ ID posted ☒ Unrelated equipment removed ☒ Demonstration made

**Recommendation:**

☒ Approve as Requested ☐ Deny ☐ Approve with conditions: \_\_\_\_\_

Inspector: 

Date: 6-8-10

**INSTRUCTIONS**

**PART I GENERAL INFORMATION**

- Enter the name of the operator exactly as it appears on the Organizational Report
- If a previously approved TA request has expired, or will be expiring in the near future, select "Renewal". Otherwise select "New".

**PART II WELL AND LEASE INFORMATION**

- Provide all of the information requested to identify the current well condition. This is important to assess the relative risks the well may pose to release production fluids into the environment or to contaminate USDW's.
- A completed WELL FLUID LEVEL/PRESSURE TEST REPORT or the results of the most recent MIT must be attached to this application or submitted before this application is approved.

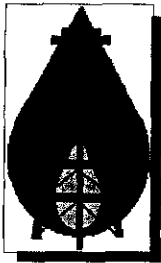
**PART III PURPOSE OF REQUEST**

- A – Provide a detailed explanation of the reason for requesting TA for this well. Typical reasons include a lack of infrastructure development, contractual barriers, time to conduct detailed engineering/geologic evaluations, or the need to perform extensive workover or recompletion operations before operations resume.
- B - A complete description should be provided of all improvements or workovers that will be required, if any, before returning the well to production. The list should be specific and address any improvements needed to oil/water separation equipment, crude oil storage tanks, flow lines, secondary containment, produced water storage vessels, water injection facilities, access roads, and any completion/workover work that will be required during the period of TA.
- C – Provide a timetable for completing the steps identified in B above including dates by which the activities are intended to be completed and the date the well is expected to be returned to active production.

**PART IV AFFIRMATION**

- The TA request must be signed by the operator or authorized representative to affirm that all of the information provided in this form is true to the best of their knowledge and belief.

**NOTE: SUBMIT COMPLETED APPLICATION TO INSPECTOR**



## TEMPORARY ABANDONMENT AUTHORIZATION

Form No. P1

Revised 1/15/2002

INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 W. Washington St., Rm. 293

Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet - <http://www.in.gov/dnroil>

Opus Oil Properties LLC

280 E. 96th Street, Suite 160

Indianapolis IN 46240-

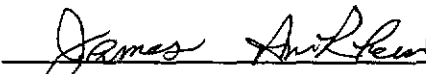
is hereby authorized to temporarily abandon the following well:

Permit No.	Well No.	Lease Name	Township Range	Section	Quarters
53114	1	Noel Carpenter	20 N 15 E	17	SW SW SW

This authorization is valid until **6/8/2015** under the following conditions:

1. An intact, leak free wellhead or cap with a valve configured to monitor casing or casing-tubing annulus pressure is maintained on the well.
2. The well site is kept free of unnecessary equipment, vegetation, and debris
3. Well identification is posted and maintained per 312 IAC 16-5-10
4. A bond is maintained on the well as required per 312 IAC 16-5
5. The well is not operated
6. The well does not threaten an underground source of drinking water.
7. If a fluid level check was used to demonstrate well integrity you must perform a fluid level check no later than **6/23/2011** and annually thereafter until this authorization expires.

### IMPORTANT

  
FOR THE DIVISION OF OIL AND GAS

If this well is a Class II well, the issuance of this Temporary Abandonment authorization voids the injection authorization for this well and you **MUST** obtain a new injection authorization letter before injecting into this well.

Renewal of temporary abandonment status will only be granted if you have submitted a renewal justification with adequate supporting documentation and the well passes a demonstration per 312 IAC 16-5-19(d).

If you place the well in operation or to obtain further information about the requirements of this temporary abandonment permit you should contact oil and gas inspector jwhite



# WELL COMPLETION/ RE-COMPLETION REPORT

Form No. R3 (Formerly Form No. R4-8-1991)  
Revised on 8/16/1999

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055  
FAX (317) 232-1550  
Internet: <http://www.state.in.us/dnroil>

*cont oky*  
*SPS 3 July 08*

### Purpose of report

☒ Completion ☐ Re-completion ☐ Conversion

☒ Check here if you want the completion information to remain confidential for 1 year.

### FOR STATE USE ONLY

Date filed

Date released

## PART I

### GENERAL INFORMATION

Name of operator Opus Oil Properties, LLC	Telephone number (317)819-1878	Permit number 53133
Address of operator ( <input type="checkbox"/> Check here if this is a new address ) 841 Alverna Drive		
City Indianapolis	State IN	Zip code 46260

## PART II

### LOCATION INFORMATION

Name of lease Mabel Thornburg					Well number 1		Elevation (G.L.) 1133	
Section 29	Township 20N	Range 15E	1/4 SE	1/4 SW	Footage's: 166 ft. from <input type="checkbox"/> N, <input checked="" type="checkbox"/> S, <input type="checkbox"/> NW, <input type="checkbox"/> SE line 696 ft. from <input checked="" type="checkbox"/> E, <input type="checkbox"/> W, <input type="checkbox"/> NE, <input type="checkbox"/> SW line			
County Randolph		Distance to the nearest well capable of producing from the same formation <u>1100</u> ft. Note: This information is only required for Oil, Gas and Dual completion wells.						

## PART III

### WELL CONSTRUCTION

NOTE: This information is not required for Geologic/ structure test wells or Individual/ county test holes

Casing Specifications			Cement (In Sacks or Cubic Feet)				Hole	
Casing size O.D. (Inches)	Wt./ ft. ( lbs. ) - Grade	Setting depth	Stage 1 Volume	Stage 1 Class- yield per sack	Stage 2 or total volume if 1 stage	Stage 2 or total Class- yield per sack	Depth	Diameter (Inches)
Surface 8.62	NEW lbs. - N/A	122 ft.	55 SX	Class A -1.18		-	122 ft.	12.25
Intermed. 6.62	NEW lbs. - N/A	501 ft.	55 sx	Class A -1.18		-	501 ft.	7.88
Long str.	lbs. -	ft.				-	1255 ft.	6.00
Tubing	lbs. -	ft.						

Packer setting depth ____ ft. Packer setting depth ____ ft. Packer setting depth ____ ft.	Centralizers at <u>150</u> ft. <u>250</u> ft. <u>450</u> ft. ____ ft.  Casing perforated From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft.	NOTE: For Class II Enhanced recovery and Saltwater disposal wells the well construction information must match the specifications of the written permit. If the information is different you must submit form no. A7 to request a modification of the existing permit conditions.
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## PART IV

### COMPLETION INFORMATION

Completion type ( Check one only )		
<input type="checkbox"/> Dry hole <input type="checkbox"/> Oil well <input checked="" type="checkbox"/> Gas well <input type="checkbox"/> Non commercial gas well	<input type="checkbox"/> Gas storage/ observation well <input type="checkbox"/> Geologic/ structure test well <input type="checkbox"/> Non potable water supply well <input type="checkbox"/> Saltwater disposal Class II well	<input type="checkbox"/> Enhanced recovery Class II well <input type="checkbox"/> Dual completion Oil/ Class II well <input type="checkbox"/> Dual completion Gas/ Class II well
Date (Enter one only) Completed <u>12/16/2006</u>	Tools Rotary from 0 ft. to 1255 ft. Cable from ____ ft. to ____ ft.	Total Depths Drillers 1255 ft. Loggers 1256 ft.

Continued on next page





# APPLICATION FOR TEMPORARY ABANDONMENT or PLUGGING DEFERRAL

Form No. A3  
Revised on 3/16/2006

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

### FOR STATE USE ONLY

Date received:

5-7-07

Date approved:

5-15-07

Approved by:

Jon Sullivan  
for HLM

Valid thru:

6-1-2016

### PART I

### GENERAL INFORMATION

Name of Operator:

Opus Oil Properties, LLC

Telephone number:

(317) 819 - 1878

Permit number:

52047

Address of Operator:

841 Alverna Drive, Indianapolis, IN 46260

53133

Type of submission (Check only one)

☐ Plugging Deferral until \_\_\_\_\_

☒ X TA New

☐ TA Renewal

### PART II

### WELL AND LEASE INFORMATION

Name of lease:

Mabel Thornburg

Well number:

1 (A)

County:

Randolph

Township:

20 N

Range:

15 E

Section:

29

1/4:

SE

1/4:

SW

Footage's: 166 from ☐ N, ☒ S, ☐ NW, ☐ SE line

696 ft. from ☒ E, ☐ W, ☐ NE, ☐ SW line

Well Type (Check only one):

☐ Oil

☒ X Gas

☐ Disposal

☐ Enhanced Recovery

☐ Other, specify: \_\_\_\_\_

Date well drilled:

12.16/2006 completed

Depth of surface casing:

501ft.

Is surface casing cemented to surface?: ☒ Yes ☐ No ☐ Unknown

If No, number of sacks cement & yield: \_\_\_\_\_

Is well equipped with: Long string cemented to surface? ☐ Yes ☐ No ☐ Unknown

If No, number of sacks cement & yield: \_\_\_\_\_

Intermediate or coal protection string cemented to surface? ☒ Yes ☐ No ☐ Unknown

If No, number of sacks cement & yield: \_\_\_\_\_

Select all that apply: Well is equipped with ☐ Rods and Tubing ☐ Tubing and Packer ☐ Tubing with no Packer

☐ Packer set at \_\_\_\_\_ depth

☐ No Tubing

☐ Bridge plug at \_\_\_\_\_ depth

☐ Other: \_\_\_\_\_

Is the well equipped with a wellhead, stuffing-box assembly, or other fittings or valves capable of providing long-term containment of any wellbore fluids? ☒ Yes ☐ No

If No, describe modifications that will be made to ensure that all wellbore fluids will be contained within the well and not released into the environment during the period of Temporary Abandonment: \_\_\_\_\_

Is well currently active?: ☐ Yes ☐ No

If No, date well became inactive: 8/9/06

Is a copy of the FLUID LEVEL TEST REPORT or the results of the most recent MIT for the well attached with this application?

☐ Yes ☐ No NOTE: A completed FLUID LEVEL/PRESSURE TEST REPORT, MIT or other demonstration of well integrity must be submitted before this application can be approved

NOTE: WELL IS NEW, HAS LITTLE/NO FLUIDS. WELL HAS HIGHER PRESSURE & YIELD (110 MCFD) WITH CIRCULATED CEMENT

### PART III

### PURPOSE OF TA REQUEST

The following information is required for all Temporary Abandonment requests: (Attach additional sheets if needed)

Skip to Part IV if requesting Plugging Deferral

A. Reason for requesting Temporary Abandonment: Well is being evaluated as part of a larger project for additional completion techniques and flow rate testing prior to installation of gathering lines, processing equipment, etc

B. Improvements or workovers required (if any): Additional stimulations may be used, and/or well deepening

C. Time schedule for returning well to production: Well is new has never been produced. Timetable for production is subject to additional work in 2007, and possible production in 2008 pending many project details. TA is requested for 3 years until June 2010.

**PART IV**

**AFFIRMATION**

I affirm under penalty of perjury that the information provided in this form is true to the best of my knowledge and belief.

Signature of operator or authorized agent

Date signed  
May 4, 2007

**FOR DIVISION USE ONLY**

**Inspection checklist:**

☒ Surface sealed ☒ Pits filled ☒ ID posted ☒ Unrelated equipment removed ☐ Demonstration made

**Recommendation:**

☐ Approve as Requested ☐ Deny ☐ Approve with conditions: \_\_\_\_\_

Inspector:

Date: 5-29-07

**INSTRUCTIONS**

**PART I GENERAL INFORMATION**

- Enter the name of the operator exactly as it appears on the Organizational Report
- If a previously approved TA request has expired, or will be expiring in the near future, select "Renewal". Otherwise select "New".

**PART II WELL AND LEASE INFORMATION**

- Provide all of the information requested to identify the current well condition. This is important to assess the relative risks the well may pose to release production fluids into the environment or to contaminate USDW's.
- A completed WELL FLUID LEVEL/PRESSURE TEST REPORT or the results of the most recent MIT must be attached to this application or submitted before this application is approved.

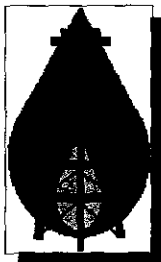
**PART III PURPOSE OF REQUEST**

- A – Provide a detailed explanation of the reason for requesting TA for this well. Typical reasons include a lack of infrastructure development, contractual barriers, time to conduct detailed engineering/geologic evaluations, or the need to perform extensive workover or recompletion operations before operations resume.
- B - A complete description should be provided of all improvements or workovers that will be required, if any, before returning the well to production. The list should be specific and address any improvements needed to oil/water separation equipment, crude oil storage tanks, flow lines, secondary containment, produced water storage vessels, water injection facilities, access roads, and any completion/workover work that will be required during the period of TA.
- C – Provide a timetable for completing the steps identified in B above including dates by which the activities are intended to be completed and the date the well is expected to be returned to active production.

**PART IV AFFIRMATION**

- The TA request must be signed by the operator or authorized representative to affirm that all of the information provided in this form is true to the best of their knowledge and belief.

**NOTE: SUBMIT COMPLETED APPLICATION TO INSPECTOR**



## TEMPORARY ABANDONMENT AUTHORIZATION

Form No. P1

Revised 1/15/2002

INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 W. Washington St., Rm. 293

Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet - <http://www.in.gov/dnroil>

Opus Oil Properties LLC

841 Alverna Drive

Indianapolis IN 46260-

is hereby authorized to temporarily abandon the following well

Permit No.	Well No.	Lease Name	Township	Range	Section	Quarters
53133	1A	Mabel Thornburg	20 N	15 E	29	se sw

This authorization is valid until 6/1/2010 under the following conditions:

1. An intact, leak free wellhead or cap with a valve configured to monitor casing or casing-tubing annulus pressure is maintained on the well.
2. The well site is kept free of unnecessary equipment, vegetation, and debris
3. Well identification is posted and maintained per 312 IAC 16-5-10
4. A bond is maintained on the well as required per 312 IAC 16-5
5. The well is not operated
6. The well does not threaten an underground source of drinking water.

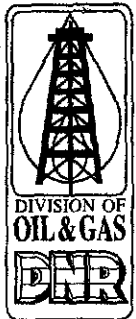
Jim AmRhein, Assistant Director  
Oil and Gas Division

### IMPORTANT

If this well is a Class II well, the issuance of this Temporary Abandonment authorization voids the injection authorization for this well and you **MUST** obtain a new injection authorization letter before injecting into this well.

Renewal of temporary abandonment status will only be granted if you have submitted a renewal justification with adequate supporting documentation and the well passes a demonstration per 312 IAC 16-5-19(d).

If you place the well in operation or to obtain further information about the requirements of this temporary abandonment permit you should contact oil and gas inspector jwhite



# WELL COMPLETION/ RE-COMPLETION REPORT

Form No. R3 (Formerly Form No. R4-8-1991)  
Revised on 8/18/1999

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055  
FAX (317) 232-1550  
Internet: <http://www.state.in.us/dnroil>

### Purpose of report

☒ Completion ☐ Re-completion ☐ Conversion

☒ Check here if you want the completion information to remain confidential for 1 year.

### FOR STATE USE ONLY

Date filed

Date released

## PART I

### GENERAL INFORMATION

Name of operator Opus Oil Properties, LLC	Telephone number (317)819-1878	Permit number 52946
Address of operator ( <input type="checkbox"/> Check here if this is a new address ) 841 Alverna Drive		
City Indianapolis	State IN	Zip code 46260

## PART II

### LOCATION INFORMATION

Name of lease Hime Farm Corp.						Well number 1	Elevation (G.L.) 1118
Section 20	Township 20N	Range 15E	1/4 NE	1/4 SE	1/4 SW	Footage's: 165 ft. from <input checked="" type="checkbox"/> N, <input type="checkbox"/> S, <input type="checkbox"/> NW, <input type="checkbox"/> SE line 165 ft. from <input checked="" type="checkbox"/> E, <input type="checkbox"/> W, <input type="checkbox"/> NE, <input type="checkbox"/> SW line	
County Randolph		Distance to the nearest well capable of producing from the same formation <u>2500</u> ft. Note: This information is only required for Oil, Gas and Dual completion wells.					

## PART III

### WELL CONSTRUCTION

NOTE: This information is not required for Geologic/ structure test wells or Individual/ county test holes

Casing Specifications			Cement (In Sacks or Cubic Feet)				Hole	
Casing size O.D. (Inches)	Wt./ ft. (lbs. ) - Grade	Setting depth	Stage 1 Volume	Stage 1 Class- yield per sack	Stage 2 or total volume if 1 stage	Stage 2 or total Class- yield per sack	Depth	Diameter (Inches)
Surface 8.62	lbs. - N/A	108 ft.	<del>25</del> 44	Class A - <del>22.00</del> 1.18		-	120 ft.	12.25
Intermed. 6.62	lbs. - N/A	488 ft.	<del>25</del> 55	Class A - <del>22.00</del> 1.18		-	450 ft.	<del>8.0</del> 7.875
Long str.	lbs. -	ft.					ft.	
Tubing	lbs. -	ft.						

Packer setting depth ____ ft. Packer setting depth ____ ft. Packer setting depth ____ ft.	Centralizers at ____ ft. ____ ft. ____ ft. ____ ft.  Casing perforated From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft. From ____ ft. to ____ ft.	NOTE: For Class II Enhanced recovery and Saltwater disposal wells the well construction information must match the specifications of the written permit. If the information is different you must submit form no. A7 to request a modification of the existing permit conditions.
---	---	---

## PART IV

### COMPLETION INFORMATION

Completion type ( Check one only )		
<input type="checkbox"/> Dry hole <input type="checkbox"/> Oil well <input checked="" type="checkbox"/> Gas well <input type="checkbox"/> Non commercial gas well	<input type="checkbox"/> Gas storage/ observation well <input type="checkbox"/> Geologic/ structure test well <input type="checkbox"/> Non potable water supply well <input type="checkbox"/> Saltwater disposal Class II well	<input type="checkbox"/> Enhanced recovery Class II well <input type="checkbox"/> Dual completion Oil/ Class II well <input type="checkbox"/> Dual completion Gas/ Class II well
Date (Enter one only) Completed 8/9/2006 Re-completed Converted	Tools Rotary from 0 ft. to 1174 ft Cable from ____ ft. to ____ ft.	Total Depths Drillers 1174 ft Loggers 1165 ft.

IMPORTANT: THIS FORM MUST BE SUBMITTED WITHIN 30 DAYS AFTER THE WELL COMPLETION OR RE-COMPLETION

Continued on next page

Spec. K. Stunk 12/13/06

Geophysical Logs		Completion Intervals		Well Treatments				
(Submit 3 copies of each)		From	ft. to	ft	Frac. with	gallons	Frac. with	lbs. sand
(CDL) COMPENSATED DENSITY POROSITY		From	ft. to	ft	Frac. with	gallons	Frac. with	lbs. sand
(CNL) COMPENSATED NEUTRON POROSITY		From	ft. to	ft	Acidized with		gallons	
(ML) MICROLOG-MINILOG		From	ft. to	ft	Acidized with		gallons	
(DIL) DUAL INDUCTION		From 1124 ft. to 1144 ft			Shot with 80 quarts			
Producing formation		Initial production (First 24 hours)						
Name Trenton Limestone		Oil		barrels	Gas 15 MCF			

[illegible]

1. Only those persons whose names appear in PARTS V or VI of the Organizational Report are authorized to sign this report.
2. **If this is a directional or horizontal well you must submit a copy of the directional survey with this report.**
3. **You must submit 3 copies of ALL geophysical logs run on this well.**

## NOTICE

Pursuant to IC 14-37-7-2 and 312 IAC 16-5-17, all data associated with the permit number identified below, is being retained in the confidential records of the Division of Oil and Gas. Access to any portion of these records is permissible after: a written, and signed release statement from the operator is submitted to the division; or, the twelve (12) month confidentiality period expires. Presently, this data is scheduled to be released by the Division of Oil and Gas on:

August 9, 2007

Operator	Opus Oil Properties, LLC					Permit:	52946
Farm Name	Hime Farm Corp.					Well #	1
20	Sec.	Twp.	20N	Rge.	15E	County	Randolph

\_\_\_\_\_  
James B. AmRhein

Assistant Director  
Division of Oil and Gas

Date: 1/3/2007  
\_\_\_\_\_

INFORMATION RELEASED  
DATE 15 JAN 08  
BY [Signature]



# APPLICATION FOR TEMPORARY ABANDONMENT or PLUGGING DEFERRAL

Form No. A3  
Revised on 3/16/2006

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas  
402 W. Washington St., Rm. 293  
Indianapolis, IN 46204  
Phone (317) 232-4055 FAX (317) 232-1550  
Internet: <http://www.in.gov/dnr/dnroil/>

### FOR STATE USE ONLY

Date received:

5-7-07

Date approved:

5-15-07

Approved by:

Jim Anderson  
per H.C.M.

Valid thru:

6-1-2010

### PART I

### GENERAL INFORMATION

Name of Operator:

Opus Oil Properties, LLC

Telephone number:

(317) 819 - 1878

Permit number:

52947

Address of Operator:

841 Alverna Drive, Indianapolis, IN 46260

52946

Type of submission (Check only one)

☐ Plugging Deferral until \_\_\_\_\_

☒ X TA New

☐ TA Renewal

### PART II

### WELL AND LEASE INFORMATION

Name of lease:

Hime Farm Corporation

Well number:

1

County:

Randolph

Township:

20 N

Range:

15 E

Section:

20

1/4:

NE

1/4:

SE

1/4:

SW

Footage's: 165 ft. from ☐ N, ☐ S, ☐ NW, ☐ SE line

165 ft. from ☐ E, ☐ W, ☐ NE, ☐ SW line

Well Type (Check only one):

☐ Oil ☒ X Gas ☐ Disposal ☐ Enhanced Recovery ☐ Other, specify: \_\_\_\_\_

Date well drilled:

8/9/2006 completed

Depth of surface casing:

488 ft.

Is surface casing cemented to surface?: ☒ X Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Is well equipped with: Long string cemented to surface? ☐ Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Intermediate or coal protection string cemented to surface? ☒ X Yes ☐ No ☐ Unknown If No, number of sacks cement & yield: \_\_\_\_\_

Select all that apply: Well is equipped with ☐ Rods and Tubing ☐ Tubing and Packer ☐ Tubing with no Packer

☐ Packer set at \_\_\_\_\_ depth ☐ No Tubing ☐ Bridge plug at \_\_\_\_\_ depth ☐ Other: \_\_\_\_\_

Is the well equipped with a wellhead, stuffing-box assembly, or other fittings or valves capable of providing long-term containment of any wellbore fluids? ☒ X Yes ☐ No If No, describe modifications that will be made to ensure that all wellbore fluids will be contained within the well and not released into the environment during the period of Temporary Abandonment: \_\_\_\_\_

Is well currently active?: ☐ Yes ☐ No If No, date well became inactive: 8/9/06

Is a copy of the FLUID LEVEL TEST REPORT or the results of the most recent MIT for the well attached with this application?

☐ Yes ☐ No NOTE: A completed FLUID LEVEL/PRESSURE TEST REPORT, MIT or other demonstration of well integrity must be submitted before this application can be approved

NOTE: WELL IS NEW, HAS LITTLE/NO FLUIDS, HOME USE TO HIME HOME, AND HAS LOW PRESSURE & YIELD WITH CIRCULATED CEMENT

### PART III

### PURPOSE OF TA REQUEST

The following information is required for all Temporary Abandonment requests: (Attach additional sheets if needed)

Skip to Part IV if requesting Plugging Deferral

A. Reason for requesting Temporary Abandonment: Well is being evaluated as part of a larger project for additional completion techniques and flow rate testing prior to installation of gathering lines, processing equipment, etc

B. Improvements or workovers required (if any): Additional stimulations may be used, and/or well deepening

C. Time schedule for returning well to production: Well is new has never been produced. Timetable for production is subject to additional work in 2007, and possible production in 2008 pending many project details. TA is requested for 3 years until June 2010

**PART IV**

**AFFIRMATION**

I affirm under penalty of perjury that the information provided in this form is true to the best of my knowledge and belief.

Signature of operator or authorized agent

Date signed  
May 4, 2007

**FOR DIVISION USE ONLY**

**Inspection checklist:**

☒ Surface sealed ☒ Pits filled ☒ ID posted ☒ Unrelated equipment removed ☐ Demonstration made

**Recommendation:**

☐ Approve as Requested ☐ Deny ☐ Approve with conditions: \_\_\_\_\_

Inspector:

Date: 5-29-07

**INSTRUCTIONS**

**PART I GENERAL INFORMATION**

- Enter the name of the operator exactly as it appears on the Organizational Report
- If a previously approved TA request has expired, or will be expiring in the near future, select "Renewal". Otherwise select "New".

**PART II WELL AND LEASE INFORMATION**

- Provide all of the information requested to identify the current well condition. This is important to assess the relative risks the well may pose to release production fluids into the environment or to contaminate USDW's.
- A completed WELL FLUID LEVEL/PRESSURE TEST REPORT or the results of the most recent MIT must be attached to this application or submitted before this application is approved.

**PART III PURPOSE OF REQUEST**

- A – Provide a detailed explanation of the reason for requesting TA for this well. Typical reasons include a lack of infrastructure development, contractual barriers, time to conduct detailed engineering/geologic evaluations, or the need to perform extensive workover or recompletion operations before operations resume.
- B – A complete description should be provided of all improvements or workovers that will be required, if any, before returning the well to production. The list should be specific and address any improvements needed to oil/water separation equipment, crude oil storage tanks, flow lines, secondary containment, produced water storage vessels, water injection facilities, access roads, and any completion/workover work that will be required during the period of TA.
- C – Provide a timetable for completing the steps identified in B above including dates by which the activities are intended to be completed and the date the well is expected to be returned to active production.

**PART IV AFFIRMATION**

- The TA request must be signed by the operator or authorized representative to affirm that all of the information provided in this form is true to the best of their knowledge and belief.

**NOTE: SUBMIT COMPLETED APPLICATION TO INSPECTOR**



## TEMPORARY ABANDONMENT AUTHORIZATION

Form No. P1

Revised 1/15/2002

INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 W. Washington St., Rm. 293

Indianapolis, IN 46204

Phone (317) 232-4055

FAX (317) 232-1550

Internet - <http://www.in.gov/dnroil>

Opus Oil Properties LLC

841 Alverna Drive

Indianapolis IN 46260-

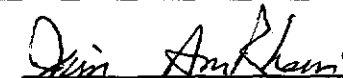
is hereby authorized to temporarily abandon the following well

Permit No.	Well No.	Lease Name	Township Range	Section	Quarters
52946	1	Hime	20 N 15 E	20	ne se sw

This authorization is valid until 6/1/2010 under the following conditions:

1. An intact, leak free wellhead or cap with a valve configured to monitor casing or casing-tubing annulus pressure is maintained on the well.
2. The well site is kept free of unnecessary equipment, vegetation, and debris
3. Well identification is posted and maintained per 312 IAC 16-5-10
4. A bond is maintained on the well as required per 312 IAC 16-5
5. The well is not operated
6. The well does not threaten an underground source of drinking water.

### IMPORTANT

  
Jim AmRhein, Assistant Director  
Oil and Gas Division

If this well is a Class II well, the issuance of this Temporary Abandonment authorization voids the injection authorization for this well and you **MUST** obtain a new injection authorization letter before injecting into this well.

Renewal of temporary abandonment status will only be granted if you have submitted a renewal justification with adequate supporting documentation and the well passes a demonstration per 312 IAC 16-5-19(d).

If you place the well in operation or to obtain further information about the requirements of this temporary abandonment permit you should contact oil and gas inspector jwhite

FIELD CHECKED BY J. CAZEE, 1967

LOCATION: 19-20N-15E  
NE NE SE  
330' NL, 330' EL  
ELEVATION: 1108 (Paulin)

DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
611 STATE OFFICE BLDG.  
DIVISION OF OIL AND GAS  
INDIANAPOLIS, INDIANA

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

## DESIGNATION

Operator Basil B. Zavoico  
Farm Name F. Tibbets  
Well No. 1

PERMIT NO. 30922 API-13-135-20001

## TYPE OF WELL

New Well ☒ Workover ☐ Deepening ☐

## LOCATION

County Randolph Twp. 20N Rge. 15E  
Section 19 NE  $\frac{1}{4}$  NE  $\frac{1}{4}$  SE  $\frac{1}{4}$   
330' from N line 330' from E line X

## ELEVATION

GL 1109 RF 1115  
1117

## TOTAL DEPTH

Driller's Log 2310 Electric Log 2304

## OPERATIONAL DATES

Commenced 2/27/67 Completed 5/17/67

## TOOLS

Rotary (interval) 0-TD Cable (interval)

## TYPE OF COMPLETION

Dry Hole ☐ Stratigraphic Test ☐  
Oil ☒ Saltwater Disposal ☐  
Gas ☒ Water Supply ☐  
Pressure Maintenance or Gas Storage:  
Secondary Recovery: ☐ Injection - Extraction ☐  
Water Injection ☐ Observation ☐  
Gas Injection ☐

## INITIAL PRODUCTION

Oil 7 Bbl Gas 250,000 cu ft.

## COMPLETION INTERVAL

Interval(s) Perf 22/ 1125-1136: Perf. 40/  
Formation Name(s) TRENTON LM. 1144-1164

## WELL TREATMENT

Shot  qts.  interval   
Shot  cuft Nitrogen interval   
Acid 3000/80,000 gals. 1125-1136 interval   
Acid 3000/80,000 gals. 1144-1164 interval   
Fracture  cuft Nitrogen interval   
Fracture  gals.  interval

## CASING RECORD

Size	Depth	Sks Cement	Csg Pulled
9 5/8"	124	60	
4 1/2"	1245	75	

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
1118/1145	Limestone	Good Fluorescence, odor, no show free oil.
1145-1150	"	Lt. Odor

The above information is complete and correct.

Date 5/19/67

Signed Lee D. Ulrey

Title Geologist

Address of Operator 680 Fifth Ave. New York, New York 10019

# FORMATION RECORD

Permit #30922

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	105	Surface clay, gravel	DIVISION OF OIL AND GAS GEOPHYSICAL LOGS ON FILE		
105	150	Dolomite, wht-lt gry.			
150	225	Dolomite, lt gry-wht, xln to sucrosic.	following logs on file		
225	237	Limestone, gry-bluish, med-cely xln.			
237	275	Shale, gry, silty dolo, w/ lime, gry, wht, mott.	_____ Electric	<input checked="" type="checkbox"/> Laterolog	
275	295	Limestone, gry-dk gry, mott, fnly xln, foss.	_____ Micro	<input checked="" type="checkbox"/> Gamma Ray - NEUTRON	
295	330	Shale, gry-grnish, silty, argill, soft	_____ Sonic	_____ Caliper	
330	350	Limestone, dk gry-blk, argill.	_____ Other		
350	460	Limestone, gry, phosphat. w/ grn-gry shale.	1128-36 1144-64 1172-78 50  <div style="border: 2px solid black; padding: 10px; margin: 10px auto; width: 200px;">RECEIVED AUG 17 1967 PETROLEUM SECTION INDIANA GEOLOGICAL SURVEY</div> <div style="border: 1px solid black; border-radius: 50%; width: 150px; height: 150px; display: flex; align-items: center; justify-content: center; margin: 10px auto;">AUG 1967 RECEIVED Dept. of Natural Resources Div. of Oil &amp; Gas By _____</div> Bond five L. 6/15/95		
460	530	Shale, gry-grnish, w/ Lime dk brn, cely xln. Sho gas 475			
530	700	Shale, gry-grnish, w/Lime dk brn, cely xln.			
700	710	Limestone, lt gry-wht, cely xln, mott.			
710	800	Shale, gry-bluish, soft w/Lime, tan-brn, xln.			
800	1040	Shale, gry-bluish-brnish gry.			
1040	1115	Shale, brn-brnish gry, calc.			
1115	1218	TRENTON Limestone, brn, tan, buff, fnly xln, Odor of oil, gas 1118-1150.			
1218	1578	BLACK RIVER Limestone, lt gry, wht, buff litho, stks dolo, gn Bent.			
1578	1630	CHAZY Limestone, dolomitio, sucros w/ gry-gn shale. 1615-1630 Shale, gry-bluish,			
1630	2310	KNOX Dolomite, tan-buff, oream, Stks sucrosic, cherty.			
2310	3310	TOTAL DEPTH			



# WELL PLUGGING PLAN

State Form 54872 (R4 / 3-20) Form No. P2

## INDIANA DEPARTMENT OF NATURAL RESOURCES

Division of Oil and Gas

402 West Washington Street, Room W293

Indianapolis, IN 46204

Telephone: (317) 232-4055

Internet: <http://www.in.gov/dnr/dnroil>

### FOR STATE USE ONLY

Date Received (month, day, year)

8-31-2021

Initials

EBY

Date Approved (month, day, year)

9-1-2021

Initials

Date Denied (month, day, year)

Initials

Date Modified (month, day, year)

Initials

### PART I

### GENERAL INFORMATION

Operator: Orphan Site

Telephone Number: 317-417-6556

E-mail: broyer@dnr.in.gov

Lease-Well Number: Fred Tibbetts #1

Well Type: Oil & Gas

Permit Number: 30922

County: Randolph

Scheduled plugging date:  
(month, day, year)

Winter 2021-22

Section 19

Township 20N

Range 15E

1/4's NE,NE,SE

#### Surface:

Size	Length	Hole	Cement
9 5/8	124		60 sx

#### Long String:

Size	Length	Hole	Cement
4.5	1245	7 7/8	75 sx

#### Liner / Intermediate Casing:

Size	Length	Hole	Cement

Estimate top of cement (TOC): 895'

Well Orientation

Vertical: ☒ Yes  
Horizontal: ☐ Yes

500-3

#### Existing Perforations:

From 1125' To 1136'  
From 1144' To 1164'  
From To

#### Proposed Perforations:

From 499 To 500  
From To  
From To

Proposed Casing to Pull - Amount:

#### Proposed cement types and volumes

Plug #1 Cmt. 1214'-875'

Cmt Type class A Volume 24 sacks

Plug #2 Cmt. 500' to surface.

Cmt Type class A Volume 143 sacks

Plug #3

Cmt Type Volume

Plug #4

Cmt Type Volume

Cmt. 1214'  
to 875'

open  
hole

TD: 2310'

PBTD: 1245'

### PART II

### AFFIRMATION

I affirm under penalty of perjury that the information provided in this plan is true and correct to the best of my knowledge and belief. Furthermore, I understand that this plan will not be valid until approved by the Division of Oil and Gas and that upon said approval, it will remain valid for a period of not more than 180 days thereafter, unless the construction of the well has changed which also voids the plan.

Signature of operator or authorized agent

Brian A. Broyer

Date signed (month, day, year)

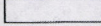
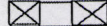
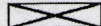
8/31/2021

Cement

CIBP

Packer

Spacer



Bottom Plug: (see above if flowing)

1214-875

Top Plug:

Perforate as needed  
to circulate full 500'-0'

tb

DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
611 STATE OFFICE BLDG.  
DIVISION OF OIL AND GAS  
INDIANAPOLIS, INDIANA

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

<b>DESIGNATION</b> Operator <u>BASIL B. ZAVOICO</u> Farm Name <u>MERRILL HARRIS</u> Well No. <u>#1</u>		<b>TYPE OF COMPLETION</b> Dry Hole _____ Stratigraphic Test _____ Oil _____ Saltwater Disposal _____ Gas <u>X</u> _____ Water Supply _____ Pressure Maintenance or _____ Gas Storage: _____ Secondary Recovery: _____ Water Injection _____ Injection - Extraction _____ Gas Injection _____ Observation _____																													
<b>PERMIT NO.</b> <u>31351</u>																															
<b>TYPE OF WELL</b> New Well <u>X</u> Workover _____ Deepening _____		<b>INITIAL PRODUCTION</b> Oil _____ Gas <u>200,000 cu ft/24</u>																													
<b>LOCATION</b> County <u>RANDOLPH</u> Twp. <u>20N</u> Rge. <u>15E</u> Section <u>29</u> NW $\frac{1}{4}$ NW $\frac{1}{4}$ SW $\frac{1}{4}$ <u>330'</u> from N line <u>330'</u> from <u>W</u> line		<b>COMPLETION INTERVAL</b> Interval(s) <u>1133-50 (34 perfs); 1183-96</u> Formation Name(s) <u>TRENTON LIME (26 perfs)</u>																													
<b>ELEVATION</b> <u>1126 GL</u> <u>1136 KB</u>		<b>WELL TREATMENT</b> Shot _____ qts. _____ interval Shot _____ qts. _____ interval Acid <u>8000 15% HCl</u> gals. <u>1130-50</u> interval Acid _____ gals. <u>1186-93</u> interval Fracture _____ gals. _____ interval Fracture _____ gals. _____ interval																													
<b>TOTAL DEPTH</b> Driller's Log <u>2010</u> Electric Log <u>2040</u>		<b>CASING RECORD</b> <table border="1"><thead><tr><th>Size</th><th>Depth</th><th>Sks Cement</th><th>Csg Pulled</th></tr></thead><tbody><tr><td><u>8 5/8"</u></td><td><u>110</u></td><td><u>80</u></td><td></td></tr><tr><td><u>4 1/2"</u></td><td><u>1254</u></td><td><u>100</u></td><td></td></tr><tr><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td></tr><tr><td></td><td></td><td></td><td></td></tr></tbody></table>		Size	Depth	Sks Cement	Csg Pulled	<u>8 5/8"</u>	<u>110</u>	<u>80</u>		<u>4 1/2"</u>	<u>1254</u>	<u>100</u>																	
Size	Depth	Sks Cement	Csg Pulled																												
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<u>4 1/2"</u>	<u>1254</u>	<u>100</u>																													
<b>OPERATIONAL DATES</b> Commenced <u>9/22/67</u> Completed <u>11/15/67</u>																															
<b>TOOLS</b> Rotary (interval) <u>X</u> Cable (interval) _____																															

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
1128-1208	Limestone	Limestone buff, tan, wht, low poro and perm Odor of gas, oil fluor from 1132-1146.

The above information is complete and correct.

Signed \_\_\_\_\_

Date 12/25/67

Title Geologist

Address of Operator 680 FIFTH AVE. NEW YORK, NEW YORK 10019

COPY SENT TO  
PETROLEUM SECTION

GIVE COMPLETE FORMATION RECORD ON REVERSE SIDE

# FORMATION RECORD

Permit #31351

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	110	Surface clays, sands, gravel			
110	245	Dolomitic Lime, wht, lt gry buff v fnly xln. sli vuggy			Drill Stem Test 3 hr. 1131-1190 Rec gas to surface 10 mih. 20' blk drlg fluid. BHP 312#/in <sup>2</sup>
245	259	Shale gray bluish silty			
259	310	Dolomitic Lime, gry wht v fnly xln, sli vuggy			
310	340	Shale green soft muddy			
340	425	Limestone, dk gry xln sli phos sli foss.			2 hr. 1564-1675 Rec. 420' drilling fluid, 300' sulphury muddy water. BHP 391#/in <sup>2</sup>
425	455	Limestone, gry xln sli foss w/ Shale gry gn			
455	700	Shale grn gry soft, w/ Lime gry dk gry xln sli foss			
700	730	Limestone, brn, buff, xln foss sli bluish chert.			
730	880	Shale gry green, sli bluish soft			
880	1040	Shale gry grn sli bluish soft w/ shale brn silty fissle			
1040	1120	Shale, brn gry brn calc soft			
1120	1129	Shale same w/ stks grn bluish shale.			
1129		TRENTON LIME			
1129	1170	Limestone, buff brn to wht v fnly xln good odor good fluor			
1170	1190	Limestone same scatt fluor ft odor.			
1190	1225	Limestone buff brn to wht v fnly xln			
1225		BLACK RIVER			
1225	1240	Limestone tan brn litho brittle qtz filled vugs			
1240	1370	Limestone tan brn buff gry dense litho to v sli xln sli cherty			
1370	1385	Limestone wht lt gray dense to v fnly xln trc bluish bent			
1385	1585	Limestone tan brn buff gry sli cherty dense to vv fnly xln scatt vuggs qtz filled.			
1585	1604	CHAZY Limestone dolomitic greenish, tan, suc, vv fnly xln w/ greenish shale.			
1604		KNOX			
1604	1700	Dolomitic Lime tan buff sli suc fr poro sli cherty			
1700	1900	Dolomitic lime wht buff li gry fnly xln suc sli pyritic			
1900	1935	Dolomitic Lime tan brn buff some grnish to gry sli vuggy			
1935	2010	Dolomitic Lime grayish green vv fnly xln sli vuggy w/ wht milky chert.			
	2010	Driller Total Depth			



API.-13-135-20004  
DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
DIVISION OF OIL & GAS

COUNTY **RANDOLPH** SECTION **29** T. **20N** R. **15E**  
COMPANY **BASIL B. ZAVOICO** WELL NO. **1**  
FARM NAME **MERRIL HARRIS ET AL**  
ELEV. **1125.45'** TWP. **WAYNE** POOL **HARRISVILLE**

CASING		SPOT	TOP	DRILLER OR SAMPLE	ELEC
SIZE	DEPTH				
8	110	330' NL	Mansfield		
		330' WL	Penn. Sd.		
			B. Penn.		
			Up. Kincaid		
4	1254	NW NW SW	Kincaid		
			Lo. Kincaid		
			Degonia		
			Clore		
			Palestine		
			Up. Menard		
			Menard		
			Lo. Menard		
			Walt'burg		
			"		
			Vienna		
			T. S. (Jett)		
			"		
			Up. G. D.		
			Lo. G. D.		
			Hd. (Jones)		
			"		
			Golconda		
			Jackson		
			Barlow Ls.		
			Cypress		
			"		
			Up. Pt. Creek		
			Lo. Pt. Creek		
			Beth-Ben		
			Up. Renault		
			Renault		
			Aux Vases		
			" "		
			St. Gen.		
			O'hara-		
			Rosiclare		
			McClosky		
			"		
			"		
			St. Louis		
			Salem		
			Chatt		
			Dev. Ls.		
			Silurian		
			Trenton		
			St. Peter		
			T. D.		

PERMIT NO. **31351**  
CONT. DEPTH **3700'** - **GRANITE**  
DRILLER **BUCKEYE DRLG. CO., INC.**  
DATE **9-12-67** ACTIVITY **9/20/67**  
**delg.**  
**subst. perf. Acid.**  
**200,000**  
**IPF. Cubic ft.**  
**gas per day**  
**680 FIFTH AVENUE**  
**NEW YORK, N.Y. 10019**  
**SAMPLES**  
**REQUIRED**  
**COMPLETED**  
**Knay**  
**2011**  
**N30**  
**1604**  
**2038**

FIELD CHECKED BY D. SULLIVAN, 1968

LOCATION: 32-20N-15E

NW NW NE

330' NL, 330' WL

ELEVATION: 1135 (Paulin)

DEPARTMENT OF NATURAL RESOURCES

STATE OF INDIANA

611 STATE OFFICE BLDG.

DIVISION OF OIL AND GAS

INDIANAPOLIS, INDIANA

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

<b>DESIGNATION</b> Operator <u>Basil B. Zavoico</u> Farm Name <u>James A. Frazier</u> Well No. <u>1</u> <div style="text-align: right;"><u>API-13-135-20007</u></div>	<b>TYPE OF COMPLETION</b> Dry Hole _____ Stratigraphic Test _____ Oil _____ Saltwater Disposal _____ Gas <u>X</u> _____ Water Supply _____ Pressure Maintenance or _____ Gas Storage: _____ Secondary Recovery: _____ Injection - Extraction _____ Water Injection _____ Observation _____ Gas Injection _____																								
<b>PERMIT NO.</b> <u>31758</u>	<b>INITIAL PRODUCTION</b> Oil _____ Gas <u>210,000 MCF</u>																								
<b>TYPE OF WELL</b> New Well <u>X</u> Workover _____ Deepening _____	<b>COMPLETION INTERVAL</b> Interval(s) <u>1152' - 1162'</u> Formation Name(s) <u>Trenton</u>																								
<b>LOCATION</b> County <u>Randolph</u> Twp. <u>20N</u> Rge. <u>15 East</u> Section <u>32</u> NW $\frac{1}{4}$ NW $\frac{1}{4}$ NE $\frac{1}{4}$ <u>330'</u> from N line <u>330'</u> from W line	<b>WELL TREATMENT</b> Shot _____ qts. _____ interval _____ Shot _____ qts. _____ interval _____ Acid <u>8,000</u> gals. <u>1146-1181'</u> interval _____ Acid _____ gals. _____ interval _____ Fracture _____ gals. _____ interval _____ Fracture _____ gals. _____ interval _____																								
<b>ELEVATION</b> <u>1134.4</u> <u>GI</u> <u>DF</u> <u>1136</u> <u>mean</u>	<b>CASING RECORD</b> <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th>Size</th> <th>Depth</th> <th>Sks Cement</th> <th>Csg. Pulled</th> </tr> </thead> <tbody> <tr> <td>13"</td> <td>22'</td> <td></td> <td>22'</td> </tr> <tr> <td>10-3/4"</td> <td>131'</td> <td>None</td> <td>0</td> </tr> <tr> <td>8-5/8"</td> <td>189'</td> <td></td> <td>189'</td> </tr> <tr> <td>7"</td> <td>505'</td> <td></td> <td>505'</td> </tr> <tr> <td>5-1/2"</td> <td>1608'</td> <td>275</td> <td>0</td> </tr> </tbody> </table>	Size	Depth	Sks Cement	Csg. Pulled	13"	22'		22'	10-3/4"	131'	None	0	8-5/8"	189'		189'	7"	505'		505'	5-1/2"	1608'	275	0
Size	Depth	Sks Cement	Csg. Pulled																						
13"	22'		22'																						
10-3/4"	131'	None	0																						
8-5/8"	189'		189'																						
7"	505'		505'																						
5-1/2"	1608'	275	0																						
<b>TOTAL DEPTH</b> <u>PBTD - 1285'</u> Driller's Log <u>1694</u> Electric Log <u>1694</u>																									
<b>OPERATIONAL DATES</b> Commenced <u>6-13-68</u> Completed <u>9-8-68</u>																									
<b>TOOLS</b> Rotary (interval) _____ Cable (interval) <u>0 to 1694'</u>																									

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
1181-1183	Limestone	Gas
1173-1178	"	"
1163-1169	"	"
1146-1160	"	"

The above information is complete and correct.

Date November 28, 1968

Address of Operator 680 Fifth Avenue New York, N.Y.

Signed

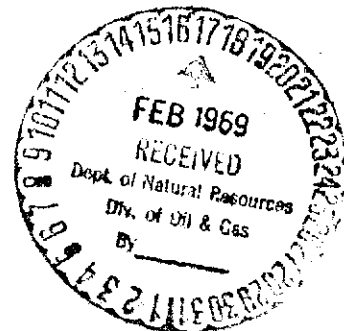
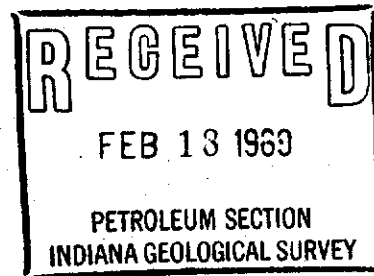
Title

# FORMATION RECORD

Permit #31758

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	10	Surface			
10	131	Sand and gravel			
131	186	Lime			
186	188	Mud			
188	255	Lime			
255	263	Shale			
263	300	Lime and Shale			
300	340	Shale			
340	455	Lime and Shale			
455	505	Shale			
505	535	Lime and Shale			
535	840	Shale			
840	925	Brown Shale			
925	1138	Shale			
1138	1593	Lime (Gas) <i>Trenton</i>			
1593	1595	Green Shale			
1595	1625	Lime and Shale			
1625	1694	Lime			
		T.D. 1694'			
		BBTD 1285'			

*perm Review  
6-5-95*



**API.-13-135-20007**  
**DEPARTMENT OF NATURAL RESOURCES**  
**STATE OF INDIANA**  
**DIVISION OF OIL & GAS**

COUNTY **RANDOLPH** SECTION **32** T. **20N** R. **15E**  
 COMPANY **BASIL B. ZAVOICO** WELL NO. **1**  
 FARM NAME **JAMES A. FRAZIER**  
 ELEV. **1134.4'** TWP. **WAYNE** POOL **HARRISVILLE**

CASING		SPOT	TOP	DRILLER OR SAMPLE	ELEC
SIZE	DEPTH				
10	68	330' NL 330' WL  NW NW NE	Mansfield		
9	504		Penn. Sd.		
			B. Penn.		
			Up. Kincaid		
			Kincaid		
			Lo. Kincaid		
			Degonia		
			Clore		
			Palestine		
			Up. Menard		
			Menard		
			Lo. Menard		
			Walt'burg		
			"		
			Vienna		
			T. S. (Jett)		
			"		
			Up. G. D.		
			Lo. G. D.		
			Hd. (Jones)		
			"		
			Golconda		
			Jackson		
			Barlow Ls.		
			Cypress		
			"		
			Up. Pt. Creek		
			Lo. Pt. Creek		
			Beth-Ben		
			Up. Renault		
			Renault		
			Aux Vases		
			" "		
			St. Gen.		
			O'hara-		
			Rosiclare		
			McClosky		
			"		
			"		
			St. Louis		
			Salem		
			Chatt		
			Dev. Ls.		
			Silurian		
			Trenton		
			St. Peter		
			T. D.		

PERMIT NO. **31758**  
 CONT. DEPTH **3700'** **GRANITE**  
 DRILLER **QUASAR, INC.**  
 DATE **5-29-68** ACTIVITY  
**MAY 31 1968** *loc.*  
**JUL 31 1968** *delg.*

*Completed as test shot  
in gas well.*

**COMPLETED**

**680 FIFTH AVENUE  
 NEW YORK, N.Y.  
 ZIP CODE - 10019**

**SAMPLES  
 REQUIRED**

*1136*  
*Black mine*  
*1694*  
*1136*  
*1512-17*  
*1300*

ack'd 5/5/69 th

DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
Division of Oil and Gas  
606 State Office Building  
Indianapolis, Indiana 46204

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

## DESIGNATION

Operator BAZIL B. ZAVOICO  
Farm Name JAMES A. FRAZIER  
Well No. 2

## TYPE OF COMPLETION

Dry Hole \_\_\_\_\_ Stratigraphic Test \_\_\_\_\_  
Oil \_\_\_\_\_ Saltwater Disposal \_\_\_\_\_  
Gas X \_\_\_\_\_ Water Supply \_\_\_\_\_  
Pressure Maintenance or \_\_\_\_\_ Gas Storage: \_\_\_\_\_  
Secondary Recovery: \_\_\_\_\_  
Water Injection \_\_\_\_\_ Injection - Extraction \_\_\_\_\_  
Gas Injection \_\_\_\_\_ Observation \_\_\_\_\_

PERMIT NO. 31891

## TYPE OF WELL

New Well X Workover \_\_\_\_\_ Deepening \_\_\_\_\_

## INITIAL PRODUCTION

Oil \_\_\_\_\_ Gas 17 mcf thru 1/8" choke

## LOCATION

County RANDOLPH Twp. 20N Rge. 15E  
Section 29 NE 1/4 NE 1/4 SE 1/4 SW 1/4  
330 from N line 330 from E line

## COMPLETION INTERVAL

Interval(s) \_\_\_\_\_  
Formation Name(s) \_\_\_\_\_

ELEVATION 1125.6

## TOTAL DEPTH

Driller's Log \_\_\_\_\_ Electric Log \_\_\_\_\_

## WELL TREATMENT

Shot	_____	qts.	_____	interval	_____
Shot	_____	qts.	_____	interval	_____
Acid	<u>10,000</u>	gals.	<u>1152-1170</u>	interval	_____
Acid	_____	gals.	_____	interval	_____
Fracture	_____	gals.	_____	interval	_____
Fracture	_____	gals.	_____	interval	_____

## OPERATIONAL DATES

Commenced 1670 PBTD - 1204  
Completed 1672

## CASING RECORD

Size	Depth	Sks Cement	Csg Pulled
<u>13 5/8"</u>	<u>18'</u>	_____	<u>0</u>
<u>5 1/2"</u>	<u>1152'</u>	<u>60</u>	<u>0</u>
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

## TOOLS

Rotary (interval) \_\_\_\_\_ Cable (interval) 0-1672

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
<u>1166-1170</u>	<u>limestone</u>	_____
<u>1155-1158</u>	<u>limestone</u>	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

The above information is complete and correct.

Signed \_\_\_\_\_

Date 4-30-69

Title Agent

Address of Operator 680 Fifth Ave. New York N.Y.

## FORMATION RECORD

[illegible]

DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
DIVISION OF OIL & GAS

COUNTY **RANDOLPH** SECTION **29** T. **20N** R. **15E**  
COMPANY **JAMES A. FRAZIER** *20010* WELL NO. **2**  
FARM NAME **BASIL B. ZAVOICO** *FRAZIER*  
ELEV. **1125.6'** TWP. **WAYNE** POOL **HARRISVILLE**

CASING		SPOT	TOP	DRILLER OR SAMPLE	ELEC
SIZE	DEPTH				
<i>8</i>	<i>188</i>	<b>330'NL</b>	Mansfield		
		<b>330'EL</b>	Penn. Sd.		
			B. Penn.		
			Up. Kincaid		
			Kincaid		
			Lo. Kincaid		
			Degonia		
			Clore		
			Palestine		
			Up. Menard		
			Menard		
			Lo. Menard		
			Walt'burg		
			"		
			Vienna		
			T. S. (Jett)		
			"		
			Up. G. D.		
			Lo. G. D.		
			Hd. (Jones)		
			"		
			Golconda		
			Jackson		
			Barlow Ls.		
			Cypress		
			"		
			Up. Pt. Creek		
			Lo. Pt. Creek		
			Beth-Ben		
			Up. Renault		
			Renault		
			Aux Vases		
			"		
			"		
			St. Gen.		
			O'hara-		
			Rosiclare		
			McClosky		
			"		
			"		
			St. Louis		
			Salem		
			Chatt		
			Dev. Ls.		
			Silurian		
			Trenton		
			St. Peter	<i>1150</i>	
			T. D.	<i>1605</i>	
				<i>1600 1670</i>	

**NE NE SE**

PERMIT NO. **31891**  
CONT. DEPTH **3700'** **GRANITE**  
DRILLER **QUASAR, INC.**  
DATE **8-7-68** ACTIVITY  
*loc. 9/16/68*

*SEP 30 1968*  
*OCT 30 1968*  
*NOV 29 1968*  
*delg.*  
*delg.*  
*delg.*  
*test. gas.*  
*IPF*  
*15 MCF GPD*  
*Duxton*

**COMPLETED**

**680 FIFTH AVE.**  
**NEW YORK, N.Y.**

**SAMPLES**  
**REQUIRED**

DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
Division of Oil and Gas  
606 State Office Building  
Indianapolis, Indiana 46204

# WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

## DESIGNATION

Operator BASIL B. Zayco  
Farm Name William Chewoweth  
Well No. 1 API-13-135-20009

PERMIT NO. 32092

## TYPE OF COMPLETION

Dry Hole \_\_\_\_\_ Stratigraphic Test \_\_\_\_\_  
Oil \_\_\_\_\_ Saltwater Disposal \_\_\_\_\_  
Gas X \_\_\_\_\_ Water Supply \_\_\_\_\_  
Pressure Maintenance or \_\_\_\_\_ Gas Storage: \_\_\_\_\_  
Secondary Recovery: \_\_\_\_\_ Injection - Extraction \_\_\_\_\_  
Water Injection \_\_\_\_\_ Observation \_\_\_\_\_  
Gas Injection \_\_\_\_\_

## TYPE OF WELL

New Well X Workover \_\_\_\_\_ Deepening \_\_\_\_\_

## INITIAL PRODUCTION

Oil \_\_\_\_\_ Gas 24 MCF

## LOCATION

County RANDOLPH Twp. 20N Rge. 15E  
Section 3D SE  $\frac{1}{4}$  SW  $\frac{1}{4}$  SE  $\frac{1}{4}$   
330 from B line 330 from E line S

## COMPLETION INTERVAL

Interval(s) 1140-46  
Formation Name(s) Trenton Limestone

ELEVATION 1146.80

## WELL TREATMENT

Shot	qts.	Interval
Shot	qts.	Interval
Acid	gals.	Interval
Acid	gals.	Interval
Fracture	gals.	Interval
Fracture	gals.	Interval

TOTAL DEPTH 1609'

Driller's Log POD 1170 Electric Log None

## OPERATIONAL DATES

Commenced 1-1-69 Completed 6-14-69

## CASING RECORD

Size	Depth	Sks Cement	Csg Pulled
<u>12 3/4"</u>	<u>110</u>	<u>Drive</u>	<u>0</u>
<u>8 5/8"</u>	<u>175</u>	<u>Drive</u>	<u>0</u>
<u>7"</u>	<u>528</u>		<u>0</u>
<u>5 1/2"</u>	<u>1132</u>	<u>35 sks</u>	<u>0</u>

## TOOLS

Rotary (Interval) \_\_\_\_\_ Cable (Interval) T.W

## OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
<u>1140-46</u>	<u>Limestone</u>	<u>Gas</u>

The above information is complete and correct.

Date 11-3-69

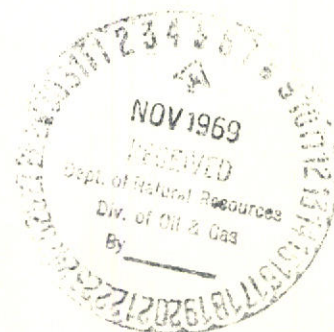
Address of Operator 680 Fifth Ave. New York, N.Y.

Signed John L. Suttler

Title Agent

## FORMATION RECORD

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	12	Clay			
12	61	Sand & Gravel			
61	66	Sand			
66	110	Sand & Shale			
110	115	Lime			
115	175	Lime & Shale Strata			
175	255	Lime			
255	296	Gray Shale & lime Shells			
296	323	Lime Shells & Shale			
323	347	" " "			
347	455	Lime			
455	486	Shale & lime Strata			
486	1131	Shale			
1131	1609	lime - Gas 1140-46			
<p>T.D. 1609</p> <p>P.B.T.D. 1170'</p>					





## WELL PLUGGING AFFIDAVIT

State Form 1115R

4.

STATE OF INDIANA

COUNTY OF

RANDOLPH

SS:

Permit No.

32092

Type of Bond

☒ \$1,000☐ \$5,000

Date Bond released

NOV 22 1983

## DESIGNATION

Name of Operator

MAYAN Energy INC.

Name of Farm

William Chenoweth

Well No.

1

ELEVATION

1148.80'

## LOCATION

County

RANDOLPH

Township

20N

Range

15E

Section

30

SE 1/4

SW 1/4

SE 1/4

From N/S line

330' SL

From E/W line

330' EL

Civil Township

WAYNE

Date Permit issued

11-20-68

Date drilling started

N/A

Date drilling completed

N/A

Kind of drilling tools used

N/A

Total depth

1132

Date plugged

11-10-83

Has this well ever produced oil or gas

OIL: ☐ Yes ☒ NoGAS: ☒ Yes ☐ No☐ DRY HOLE

Remarks

NOT ENOUGH GAS FOR HEATING

## DETAILS OF PLUGGING

MATERIALS USED  
(Rotary Mud, Cement, or  
other Materials)FROM  
(Feet)TO  
(Feet)MATERIALS USED  
(Rotary Mud, Cement, or  
other Materials)FROM  
(Feet)TO  
(Feet)

Cement

1132'

0'

IF WORKABLE COAL BEDS WERE ENCOUNTERED IN THIS HOLE, DESCRIBE THE METHOD EMPLOYED TO PROTECT SAME.  
(A workable coal bed is 24 inches or more in thickness above 1,200 feet in depth)

Please Note: The bond for this well cannot be released until all four squares below are checked "Yes"

Have pits, cellar and other  
excavations been filled?☒ Yes ☐ NoHave equipment, concrete bases and  
clebris been removed?☒ Yes ☐ NoHas surface casing been cut off below  
plow depth?☒ Yes ☐ No

Has well-site been levelled?

☒ Yes ☐ No

## CASING RECORD

SIZE

PUT IN  
WELLPULLED  
OUTLEFT IN  
WELL

REMARKS

Feet

Feet

Feet

SIZE

PUT IN  
WELLPULLED  
OUTLEFT IN  
WELL

REMARKS

Feet

Feet

Feet

10 3/4" 110'

110'

8 5/8" 175'

175'

7" 528'

528'

5 1/2" 1132'

1132'

Signature of person, Firm or Corporation having custody or control of well

MAYAN Energy INC.

Per (Name)

MAYAN Energy INC.

Street Address

212 N. WASHINGTON WINCHESTER, IND.

City, State, Zip

Signature of party supervising plugging of well

Virgil E. Lowe

Title

Street Address

4009 Virginia MUNCIE,

City, State, Zip

STATE OF INDIANA

COUNTY OF

RANDOLPH

SS:

47394

Subscribed and sworn to before me this

10

day of

November

19

83

Notary's Signature

Virgil E. Lowe

Notary's Name Typed or Printed

Virgil E. Lowe

County of Residence

DELAWARE

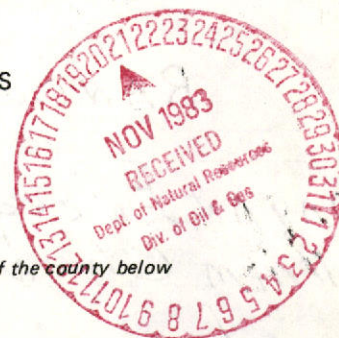
Commission Expiration Date

2-14-84

# CERTIFICATE OF COMPLIANCE

Issued by:

STATE OF INDIANA  
DEPARTMENT OF NATURAL RESOURCES  
DIVISION OF OIL AND GAS  
911 State Office Building  
Indianapolis, Indiana 46204



Instructions: The owner or operator shall file this certificate in the office of the recorder of the county below within 90 days from the certificate issue date (IC 13-4-7-23H).

STATE OF INDIANA  COUNTY OF <u>RANDOLPH</u>	SS:	Permit No.  <u>32092</u>
---	-----	--------------------------------

I, Virgil E. Lowe, a duly qualified District Oil and Gas Supervisor of the State of Indiana, do hereby certify that I have supervised the plugging and abandoning of the following well:

Name of Farm <u>William Chenoweth</u>	Well No. <u>1</u>	County <u>RANDOLPH</u>	Township <u>20N</u>	Range <u>15E</u>
From N/S line <u>330' SL</u>	From E/W line <u>330' EL</u>	Section <u>30</u>	<u>SE 1/4</u>	<u>SW 1/4 SE 1/4</u>

## CASING LEFT IN WELL

SIZE	FEET	INCHES	REMARKS
<u>10 3/4"</u>	<u>110'</u>		
<u>8 5/8"</u>	<u>175'</u>		
<u>7"</u>	<u>528'</u>		
<u>5 1/2"</u>	<u>1132'</u>		

## DETAILS OF PLUGGING

MATERIALS USED (Rotary Mud, Cement, or other Materials)	FROM (Feet)	TO (Feet)	MATERIALS USED (Rotary Mud, Cement, or other Materials)	FROM (Feet)	TO (Feet)
<u>CEMENT</u>	<u>1132'</u>	<u>0'</u>			

Date Plugging Completed (Month) <u>November</u>	Day <u>10</u>	Year <u>1983</u>	Date Abandonment Completed (Month) <u>November</u>	Day <u>10</u>	Year <u>1983</u>
--	------------------	---------------------	---	------------------	---------------------

I further certify that said well has been plugged and abandoned in accordance with the provisions of IC 13-4-7, Indiana General Assembly, and Rules and Regulations adopted pursuant thereto.

Date Certificate Issued (Month) <u>November</u>	Day <u>10</u>	Year <u>1983</u>	Oil & Gas Inspector's Signature <u>Virgil E. Lowe</u>
This Instrument prepared by <u>Virgil E. Lowe</u>			

ackd-11-5-69

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DEPARTMENT OF NATURAL RESOURCES  
STATE OF INDIANA  
Division of Oil and Gas  
606 State Office Building  
Indianapolis, Indiana 46204

## WELL COMPLETION OR RECOMPLETION REPORT AND WELL LOG

TO BE FILED IMMEDIATELY AFTER COMPLETION OF WELL  
NOTICE: IT IS NECESSARY TO SUBMIT A RECORD FOR EACH PERMIT.

<b>DESIGNATION</b> Operator <u>Basil B. Zavoico</u> Farm Name <u>Ralph C. Peacock</u> Well No. <u>1</u> <u>API-13-135-20010</u>	<b>TYPE OF COMPLETION</b> Dry Hole _____ Stratigraphic Test _____ Oil _____ Saltwater Disposal _____ Gas <u>X</u> _____ Water Supply _____ Pressure Maintenance or _____ Gas Storage: _____ Secondary Recovery: _____ Water Injection _____ Injection - Extraction _____ Gas Injection _____ Observation _____																								
<b>PERMIT NO.</b> <u>32093</u>	<b>INITIAL PRODUCTION</b> Oil _____ Gas <u>27 MCF</u>																								
<b>TYPE OF WELL</b> New Well <u>X</u> Workover _____ Deepening _____	<b>COMPLETION INTERVAL</b> Interval(s) <u>1142-81</u> Formation Name(s) _____																								
<b>LOCATION</b> County <u>Randolph</u> Twp. <u>20nd</u> Rge. <u>15E</u> Section <u>32</u> <u>SW</u> $\frac{1}{4}$ <u>SE</u> $\frac{1}{4}$ <u>NW</u> $\frac{1}{4}$ <u>330'</u> from <u>S</u> line <u>330</u> from <u>W</u> line	<b>WELL TREATMENT</b> Shot _____ qts. _____ interval _____ Shot _____ qts. _____ interval _____ Acid <u>500</u> gals. <u>1142-81</u> interval _____ Acid _____ gals. _____ interval _____ Fracture _____ gals. _____ interval _____ Fracture _____ gals. _____ interval _____																								
<b>ELEVATION</b> <u>1141.80</u>	<b>CASING RECORD</b> <table border="1" style="width: 100%; border-collapse: collapse;"><thead><tr><th>Size</th><th>Depth</th><th>Sks. Cement</th><th>Csg. Pulled</th></tr></thead><tbody><tr><td><u>10 3/4"</u></td><td><u>116</u></td><td><u>DRIVE</u></td><td><u>0</u></td></tr><tr><td><u>7"</u></td><td><u>545</u></td><td><u>25</u></td><td><u>0</u></td></tr><tr><td> </td><td> </td><td> </td><td> </td></tr><tr><td> </td><td> </td><td> </td><td> </td></tr><tr><td> </td><td> </td><td> </td><td> </td></tr></tbody></table>	Size	Depth	Sks. Cement	Csg. Pulled	<u>10 3/4"</u>	<u>116</u>	<u>DRIVE</u>	<u>0</u>	<u>7"</u>	<u>545</u>	<u>25</u>	<u>0</u>												
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<u>7"</u>	<u>545</u>	<u>25</u>	<u>0</u>																						
<b>TOTAL DEPTH</b> <u>1606'</u> Driller's Log <u>PBTD 1181</u> Electric Log <u>Above</u>																									
<b>OPERATIONAL DATES</b> Commenced <u>2-25-69</u> Completed <u>5-12-69</u>																									
<b>TOOLS</b> Rotary (interval) _____ Cable (interval) <u>T.D.</u>																									

### OCCURRENCE OF OIL AND GAS

Interval	Type of Formation (ls., ss., etc.)	Remarks (fill-up, tests, etc.)
<u>1142-55</u>	<u>Lime</u>	<u>Gas</u>

The above information is complete and correct.

Signed \_\_\_\_\_

Date 11/3/69

Title Agent

COPY SENT TO Operator

680 Fifth Avenue, New York, N.Y.

PETROLEUM SECTION

GIVE COMPLETE FORMATION RECORD ON REVERSE SIDE

# FORMATION RECORD

R.C. Peacock #1

From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)	From	To	Rock Type (describe rock types and other materials penetrated and record occurrences of oil, gas and water from surface to total depth)
0	10	Clay			
10	40	Sand + Gravel			
40	60	Gravel + Shale			
60	65	Sand			
65	116	Sand + Shale			
116	265	Lime			
265	276	Shale			
270	280	Lime			
280	335	Lime + Shale			
335	370	Shale			
370	380	Lime			
380	420	Lime + Shale			
420	435	Lime			
435	450	Shale			
450	480	Lime + Shale			
480	505	Shale			
505	510	Lime + Shale			
510	520	Shale			
520	545	Lime + Shale			
545	1142	Shale			
1142	1289	Lime			
1289	1291	Shale			
1291	1604	Lime			
1604	1606	Shale			
		T.D. 1606			
		P.B.T.D. 1181			





# PLUGGING AND ABANDONMENT REPORT

State Form 1115R3

## OPERATOR'S NOTE:

- As soon as the site restoration is complete, the Operator is to contact the Inspector.
- This report must be filed in the office of the recorder of the county in which the well was located **WITHIN 90 days** of issuance.
- Photocopy form for distribution

## FOR OFFICE USE ONLY

Bond type <input type="checkbox"/> \$1,000 <input checked="" type="checkbox"/> \$2,000 <input type="checkbox"/> \$5,000 <input type="checkbox"/> \$30,000	Date bond released 9-22-87
Well type <input type="checkbox"/> Dry <input type="checkbox"/> Oil <input checked="" type="checkbox"/> Gas <input type="checkbox"/> Disposal <input type="checkbox"/> Enhanced recovery <input type="checkbox"/> Gas Storage <input type="checkbox"/> Observation <input type="checkbox"/> Non-potable water supply <input type="checkbox"/> Geological or structure test	

## PLUGGING

Name of Operator Gold Leaf Inc. (Mayan En. U.S. Inc.)	Date well plugged 9-14-87							
Address of Operator Gary Cooper RR2 Box 77 Payne, Ok. 45880	Permit number 32093							
Name of lease Ralph C. Peacock	Well number 1							
County of well location Randolph	Section 32	Township 20N	Range 15E	1/4 SW	1/4 SE	1/4 NW	730 feet from North / South Line 330 feet from East / West Line	Total Depth (feet) 1181'

## CASING RECORD

	STRING # 4	STRING # 3	STRING # 2	STRING # 1
Casing or tubing diameter ..... (outside / inches)			7"	10"
Amount set ..... (feet)			545'	116
Amount left in well ..... (feet)				
Hole size ..... (diameter / inches)				
Cement used to set ..... (cubic feet)				

## PLUGGING RECORD

	PLUG # 1	PLUG # 2	PLUG # 3	PLUG # 4
Hole or pipe diameter ..... (inside / inches)	7"	10"		
Material used	Cement	Cement		
Depth to bottom of plug	1181'	545'		
Depth to top of plug ..... (calculated)	0'	0'		
Amount Used ..... (sacks)	207			

I certify that the information provided above is correct and accurate to the best of my knowledge.

Printed name of Operator, Operator's Rep., or person controlling well Gold Leaf Inc.	Signature X Vanny Evans	Date signed 9-15-87
Printed name of Field Inspector Virgil E. Lowe	Signature Virgil E. Lowe	Date signed 9-14-87
Address of Field Inspector (Street, city, state, ZIP code) 4009 Virginia Ave Muncie, Ind. 47304		Phone number of Field Inspector 317-288-0708

## ABANDONMENT

Date abandonment completed and site inspected (Month, day, year)	
Abandonment requirements (check if completed) <input checked="" type="checkbox"/> Excavations filled <input checked="" type="checkbox"/> Equipment and debris removed <input checked="" type="checkbox"/> Top 3 feet of casing removed <input checked="" type="checkbox"/> Site leveled	
NOTE: Appropriate "Assumption of Responsibility" form(s) must be attached for any box(es) left unchecked above.	
I certify that this well has been abandoned in accordance with provisions of IC 13-4-7 and 310 IAC 7-1.	
Signature of Field Inspector Virgil E. Lowe	Date signed 9/15/87

## Theoretical Outline

This section describes the equations and variables used in GEM and the approach for solving these equations. The flow equations are discretized using the adaptive-implicit method (Collins et al., (1992), Thomas and Thurnau., (1983), Nghiem and Li., (1989) because it encompasses both the explicit-transmissibility method and the fully-implicit method as particular cases.

The equations, variables and solution method presented in the following are variations of the approach of Collins et al., (1992).

### Flow Equations

The material-balance finite-difference equations for the components in the oil and gas phases, and for the water component are:

$$\begin{aligned} \psi_i \equiv \Delta T_o^m y_{io}^m (\Delta p^{n+1} - \gamma_o^m \Delta D) + \Delta T_g^m y_{ig}^m (\Delta p^{n+1} + \Delta P_{cog}^m - \gamma_g^m \Delta D) \\ + q_i^m - \frac{V}{\Delta t} [N_i^{n+1} - N_i^n] = 0 \quad i = 1, \dots, n_c \end{aligned} \quad (A1.1)$$

$$\psi_{n_c+1} \equiv T_w^m (\Delta p^{n+1} - \Delta P_{cwo}^m - \gamma_w^m \Delta D) + q_{n_c+1}^m - \frac{V}{\Delta t} [N_{n_c+1}^{n+1} - N_{n_c+1}^n] = 0 \quad (A1.2)$$

where  $N_i (i = 1, \dots, n_c)$  denote the moles of Component  $i$  per unit of gridblock volume, and where  $N_{n_c+1}$  denotes the moles of water per unit of gridblock volume. All other symbols are defined in the nomenclature. It is assumed that no mass transfer exists between the hydrocarbon and water phases. The superscripts  $n$  and  $n+1$  denote respectively the old and current time level. The superscript  $m$  refers to  $n$  for explicit gridblocks and  $n+1$  for fully-implicit gridblocks. In GEM, the term explicit refers to gridblocks with explicit transmissibilities where only pressure is treated implicitly.

The  $N_i$ 's are related to porosities phase molar densities, saturations and compositions as follows:

$$N_i = \phi (\rho_o S_o y_{io} + \rho_g S_g y_{ig}) \quad i = 1, \dots, n_c \quad (A1.3)$$

$$N_{n_c+1} = \phi \rho_w S_w \quad (A1.4)$$

### Phase-Equilibrium Equations

If the hydrocarbon system is in the two phase region at a given  $p$ ,  $T$  and  $N_i (i = 1, \dots, n_c)$ , the phase compositions and splits can be obtained by solving the thermodynamic-equilibrium equation

$$g_i \equiv \ln f_{ig} - \ln f_{io} = 0 \quad i = 1, \dots, n_c \quad (A1.5)$$

for  $N_{ig}$ , the moles of Component  $i$  in the gas phase. The moles of Component  $i$  in the oil phase,  $N_{io}$ , can be obtained from

$$N_{io} = N_i - N_{ig} \quad i = 1, \dots, n_c \quad (A1.6)$$

### Saturation Equation

The saturations are related to  $N_i$  and  $\rho_m (m = o, g, w)$  through the following equation

$$S_w = N_{n_c+1} / (\phi \rho_w) \quad (A1.7)$$

$$S_o = (1 - S_w) \frac{N_o / \rho_o}{N_o / \rho_o + N_g / \rho_g} \quad (A1.8)$$

$$S_g = (1 - S_w) \frac{N_g / \rho_g}{N_o / \rho_o + N_g / \rho_g} = 1 - S_w - S_o \quad (A1.9)$$

### Mole or Volume Consistency Equations

From the definition of  $N_i (i = 1, \dots, n_c+1)$ , one can write

$$\psi_p \equiv \sum_{i=1}^{n_c+1} N_i^{n+1} - \phi^{n+1} (\rho_o S_o + \rho_g S_g + \rho_w S_w)^{n+1} = 0 \quad (\text{A1.10})$$

Equation (A1.10) forces the consistency between the  $N_i$ 's and the densities, saturations, and porosities.

Equation (A1.10) can also be rewritten as follows

$$\psi'_p \equiv V \frac{\sum_{i=1}^{n_c+1} N_i^{n+1}}{(\rho_o S_o + \rho_g S_g + \rho_w S_w)^{n+1}} - V \phi^{n+1} = 0 \quad (\text{A1.11})$$

The first term in Equation (A1.11) is the volume occupied by the fluids (oil, gas, water) and the second term is the pore volume. Thus Equation (A1.11) forces the consistency between the fluid volume and the pore volume. A similar equation is referred to as volume balance equation by [Acc et al., \(1985\)](#) and [Watts \(1986\)](#).

### Decoupled Flash-Calculation Approach

Equations (A1.11), (A1.1), (A1.2), and (A1.5) form a system of  $n_b(2n_c+2)$  non-linear equation which can, in principal, be solved for the variables

$$(p, N_i, \dots, N_{n_c}, N_{n_c+1}, N_{1g}, \dots, N_{n_{cg}})^{n+1}_k \quad k = 1, \dots, n_b$$

where  $n_b$  is the number of gridblocks. This approach will be referred to as the simultaneous-solution approach.

To alleviate the complexity associated with the simultaneous-solution of all governing equations, [Collins et al., \(1992\)](#) decoupled the phase-equilibrium equations and solved them in an inner loop. The technique used in GEM is a variation of their approach and will be referred to as the decoupled-flash-calculation approach. The equations and primary variables of gridblock  $k$  are

$$\mathbf{F}_k = (\psi'_p, \psi_1, \dots, \psi_{n_c+1})^T_k \quad k = 1, \dots, n_b \quad (\text{A1.12})$$

$$\mathbf{X}_k = (p^{n+1}, N_1^{n+1}, \dots, N_{n_c+1}^{n+1})^T_k \quad k = 1, \dots, n_b \quad (\text{A1.13})$$

After every Newtonian iteration of  $\mathbf{X}$ , the phase-equilibrium Equation (A1.5) are solved to convergence.

The approach taken here separates the task of solving the consistency and flow equations from that of solving the phase-equilibrium equations. This is a desirable feature because flash calculations are localized in a module that can be developed independently. It also allows the use of different calculation techniques (e.g. Newton's method, quasi-Newton method, QNSS) and the easy implementation of stability-test procedures.

It is possible that this decoupled-flash-calculation approach may not be as efficient as the simultaneous-solution approach for systems with simple phase behavior, but it provides additional flexibility in implementing more robust flash algorithms for complex systems. It also allows the ability to repeat the flash calculations for gridblocks where convergence to unrealistic or metastable phases are obtained. The simultaneous-solution approach may require a repeat of the timestep. Note that the decoupled flash-calculation approach enforces the thermodynamic equilibrium between oil and gas at every iteration whereas in the simultaneous-solution approach, equilibrium is only satisfied after the convergence of the timestep.

## Nomenclature

$D$	depth
$f_{ij}$	fugacity of component $i$ in phase $j$
$F$	function
$g$	phase-equilibrium function
$n_b$	number of gridblocks
$n_c$	number of components
$N_i$	moles of component $i$ per unit block volume
$p$	pressure
$P_{cog}$	oil-gas capillary pressure
$P_{cwo}$	water-oil capillary pressure
$q$	injection/production rate
$t$	time
$T_j$	transmissibility of phase $j$
$V$	gridblock volume
$y_{ij}$	mole fraction of component $i$ in phase $j$
$\gamma$	specific gravity or gravity term in flow equation
$\Delta t$	timestep
$\rho_m$	molar density of phase $m$
$\phi$	porosity
$\psi$	function

## Superscripts

$(k)$	iteration level
$n$	old time level
$n+1$	new time level

## Subscripts

$i$	component
$j$	phase
$o$	oil
$g$	gas
$w$	water

## **4 Operational Procedures [40 CFR 146.82(a)(10)]**

Consistent with 40 CFR 146.88(b), injection will not occur in the annulus. Injection will only occur through the internally coated injection string. As detailed in the well construction plan, the annulus will be filled with a non-corrosive fluid, consistent with 40 CFR 146.88(c).

In this section, the maximum annual and daily injection volumes have been provided. Details on the methodology and determination of the maximum injection pressure have also been provided. Finally, an operational plan to maintain the annulus pressure and to ensure that mechanical integrity is detectable and maintained has been provided.

### **4.1 Maximum Injection Volume**

The maximum annual injection volume requested from this permit application is 450 kilotons (kT) per year. This is the volume that has been used for all computational modelling and associated CO<sub>2</sub> and pressure plume calculations. This equates to a total injected volume of 13.5 million metric tons of CO<sub>2</sub> injected over the 30-year life of the project.

Based on the maximum annual volume, the average daily volume will be 1,230 metric tons of CO<sub>2</sub> per day. It is noted that the daily volume of CO<sub>2</sub> that is injected is subject to change based on operational conditions and system maintenance.

Based on a projected CO<sub>2</sub> density equivalent to 0.401 specific gravity (SG), the average injection rate to achieve this annual injection volume is approximately 565 gallons per minute, or 13.45 barrels per minute (19,368 barrels per day).

### **4.2 Maximum Injection Pressure**

The maximum allowable injection pressure (MAIP) will be specifically calculated using the results of the step rating testing to be performed as part of the pre-operational testing program (Attachment 5: Pre-Op Testing Program, 2022). This value will be provided in a subsequent document prior to receiving the final, modified injection well permit.

#### ***4.2.1 Determination of Maximum Injection Pressure***

The CO<sub>2</sub> injection pressure will be monitored on a continuous basis at the wellhead and downhole to ensure that injection pressures do not exceed 90% of the fracture pressure of the injection zone per 40 CFR 146.88 (a). If injection pressure exceeds 90% of the injection zone fracture pressure, then the injection process will be automatically shutdown per Section 4.5.

Based on current information, 90% fracture pressure gradient is expected to be 0.75 psi/ft, which results in a maximum allowable bottomhole flowing pressure (BHFP) of 2,369 psi at a depth of 3,159 feet, which is the projected top of the Mt. Simon Sandstone (Attachment 2: AOR and Corrective Action, 2022). Fracture pressure gradient will be specifically determined using the data collected during the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022).

Computational modeling predicts that the BHFP at the top of the Mt. Simon Sandstone will be approximately 2,050 psi during the first year of normal operations and is anticipated to decline to approximately 1,700 psi after five years of injection. An average CO<sub>2</sub> fluid density of 25 lb/ft<sup>3</sup> (0.401 SG) is assumed for all hydrostatic calculations; this is representative of average conditions over the first five years of injection. Metric numbers have been used for intermediate calculations, with English units displayed for permitting purposes.

**Equation 1**

$$\text{Surface Pressure (MAIP)} = \text{BHFP} - \text{SGfluid} * 0.433 \text{psift} * (\text{Depth} - \text{headloss})(1)$$

Where, the head loss due to friction is calculated using the Moody Equation,

$$\text{head}_{\text{loss}} = f_D \frac{L}{D} \frac{\text{Velocity}_{\text{CO}_2}^2}{2g} \quad (2)$$

Where  $f_D$ , friction factor, is calculated using the Darcy-Weisbach for laminar flow (3) and Colebrook for turbulent flow (4) equations,

$$f_D = \frac{64}{\text{Re}} \quad (3)$$

$$\frac{1}{\sqrt{f_D}} = -2.0 \log_{10} \left( \frac{\varepsilon/D}{3.7} + \frac{2.51}{\text{Re} \sqrt{f_D}} \right) \quad (4)$$

$\varepsilon/D$  is the relative roughness, defined by the roughness of the pipe divided by the internal diameter (ID) of the pipe. The roughness of the pipe coating (TK-70XT) was defined as 2 microns (7.874E-05 inches) by the coating manufacturer (Tuboscope). A value of 2.632 E-05 was used for the relative roughness.

Re is the Reynolds number, which is defined as,

$$\text{Re} = \frac{\rho_{\text{CO}_2} \text{Velocity}_{\text{CO}_2} \text{ID}}{\mu_{\text{CO}_2}} \quad (5)$$

Based on the previously given inputs, an average injection velocity of 7.85 m/s (defined by a maximum annual injection rate of 450kT/yr) (25.8 ft/s), a length of pipe of 970.5 m (3,184 ft), and a viscosity of 2.760E-5 kg/m\*s a Reynold's number of 8.662E6 has been calculated.

Using this value and the relative roughness calculated above, a friction factor of 0.01 was calculated using the Colebrook equation.

This friction factor is plugged into the head loss equation, resulting in a head loss of 400 m, or 1,312.5 ft. This headloss results in a total friction loss of 227.7 psi.

By using the hydrostatic injection pressure detailed above, the calculated MAIP using Equation (1) is:

$$\begin{aligned} \text{MAIP} &= \text{Max BHFP} - 0.433 \frac{\text{psi}}{\text{ft}} * \text{SG} * (\text{Mt. Simon Top} - \text{Head Loss}) \\ &= 2,369 \text{ psi} - 0.433 \frac{\text{psi}}{\text{ft}} * 0.401 * (3,159 \text{ ft} - 1312.5 \text{ ft}) = 2,048 \text{ psi} \end{aligned}$$

The calculations above make the following assumptions:

- A constant density column of supercritical CO<sub>2</sub> from the surface to the top of the Mt. Simon Sandstone
- The density of the CO<sub>2</sub> post compression will be approximately 25 lb/ft<sup>3</sup>,
- The injection string will consist of 3.5-inch 9.2 pound per foot coated tubing,
- The pipe coating roughness (TK 70XT) will be 2 microns,
- The viscosity of the CO<sub>2</sub> will remain at 2.760 E-05 kg/m\*s.

## Thermal Option in GEM

This section describes the development of an energy equation to calculate temperature distribution in the reservoir for the compositional processes where reservoir temperature could change with time, for instance when the injected fluid is at a different temperature than the one prevailing in the reservoir. The equations to be solved are:

- Volume constraint equation: the volume of fluids must equal the pore volume.
- Component flow equations: material balance equations for oil, gas and water components.
- Energy balance equation including convection, conduction and heat losses.
- Phase equilibrium equations.

The volume constraint, component flow and phase equilibrium equations are described in [Appendix A](#). Here we focus on the energy balance equation and related aspects.

### Energy Balance Equation

To calculate the temperature distribution for the thermal cases, the following energy balance equation is added to the equation set.

$$\begin{aligned}
 \psi_T \equiv & \Delta T_o^m H_o^m (\Delta p_o^{n+1} - \tilde{\rho}_o^m g \Delta D) + \Delta T_g^m H_g^m (\Delta p_o^{n+1} + \Delta P_{cog}^m - \tilde{\rho}_g^m g \Delta D) \\
 & + \Delta T_w^m H_w^m (\Delta p_o^{n+1} - \Delta P_{cwo}^m - \tilde{\rho}_w^m g \Delta D) + \Delta \tau_c^m \Delta T^{n+1} + Q_{loss} + \sum_k H_k^{n+1} q_k^{n+1} \\
 & - \frac{V}{\Delta t} \left[ \phi^{n+1} \left( \sum_k \rho_k^{n+1} S_k^{n+1} U_k^{n+1} \right) - \phi^n \left( \sum_k \rho_k^n S_k^n U_k^n \right) \right] \\
 & - \frac{V}{\Delta t} [(1 - \phi_0) c_R \tilde{\rho}_R (T^{n+1} - T^n)] = 0, \quad k = o, g, w
 \end{aligned} \tag{E1.1}$$

where

$c_R$  = heat capacity of rock

- $H_k$  = molar enthalpy of Phase  $k$  ( $k = o, g, w$ )
- $S_k$  = saturation of Phase  $k$  ( $k = o, g, w$ )
- $Q_{loss}$  = heat loss rate to the (over/underburden) surroundings
- $T$  = temperature
- $\phi$  = Porosity (0 = initial;  $n+1$  = current timestep;  $n$  = previous timestep)
- $U_k$  =  $H_k - p/p_k$ ; molar internal energy of Phase  $k$
- $\tilde{\rho}_R$  = Rock mass density
- $\tau_c$  = total thermal conductivity of rock and fluids

Equation (E1.1) is an energy balance equation involving convection, conduction and heat losses to the surroundings.

### Enthalpy Calculations

The enthalpy of the water phase is calculated from a look-up of the steam table. The oil and gas enthalpies are calculated from an EOS as follows.

The excess enthalpy for a fluid, which is the difference of the enthalpy at  $p$  and  $T$  and the ideal gas enthalpy at zero pressure and  $T$ , can be calculated from an EOS:

$$\Delta H^E = H - H^* = RT (Z - 1) + \int_{\infty}^v \left[ T \left( \frac{\partial p}{\partial T} \right)_v - p \right] dv \quad (E1.2)$$

where

- $R$  = universal gas constant
- $v$  = molar volume
- $Z$  = compressibility factor

The above quantity is also referred to as enthalpy departure. Using Equation (E1.2), the following equation can be derived to calculate enthalpy departure for the SRK or PR EOS:

$$\Delta H^E = RT(Z - 1) + \frac{T(\partial a / \partial T) - a}{b(\delta_2 - \delta_1)} \ln \left( \frac{v + \delta_2 b}{v + \delta_1 b} \right) \quad (\text{E1.3})$$

where

$\delta_1 = 1 - \sqrt{2}$ ;  $\delta_2 = 1 + \sqrt{2}$  for the PR EOS, and

$\delta_1 = 0$ ;  $\delta_2 = 1$  for the SRK EOS

and  $a$  and  $b$  are EOS parameters.

The *API Technical Data Book - Petroleum Refining V. 2 (1983)* provides polynomials for estimating pure component enthalpies,  $H_i^*$  in the form:

$$H_i^* = \sum_{j=0}^5 a_{ji} T^j \quad (\text{E1.4})$$

where  $a_{ji}$  are the polynomial coefficients for Component  $i$ . Knowing  $\Delta H^E$  and  $H^*$ , the enthalpy  $H$  and the internal energy can be calculated from:

$$U_k = H_k - pv_k = H_k - p / \rho_k \quad (\text{E1.5})$$

### Calculation of Enthalpies for Pseudo Components

[Kesler and Lee \(1976\)](#) provide the following correlation for calculating ideal gas heat capacities for heavy-fraction pseudo components from their specific gravity and normal boiling point:

$$\begin{aligned} c_{pi}^* = & -0.32646 + 0.02678 K_{uop} \\ & - (1.3892 - 1.2122 K_{uop} + 0.03803 K_{uop}^2) \cdot 10^{-4} T - 1.5393 \cdot 10^{-7} T^2 \\ & - C_F [0.084773 - 0.080809 \rho' - (2.1773 - 2.0826 \rho') \cdot 10^{-4} T] \\ & + C_F [(0.78649 - 0.70423 \rho') \cdot 10^{-7} T^2] \end{aligned} \quad (\text{E1.6})$$

where  $\rho'$  is the specific gravity,  $T_b$  is the normal boiling point in °R,  $K_{uop}$  is the Watson characterization factor given by:

$$K_{uop} = (T_b)^{\frac{1}{3}} / \rho' \quad (\text{E1.7})$$

and

$$C_F = \left[ \left( \frac{12.8}{K_{uop}} - 1 \right) \times \left( \frac{10}{K_{uop}} - 1 \right) \times 100 \right]^2 \quad (\text{E1.8})$$

The ideal gas enthalpy is then obtained by integrating  $c_p$  in Equation (E1.6), i.e.

$$H_i^* = \int_0^T c_{pi} dT' \quad (\text{E1.9})$$

Note that Equation (E1.6) is of the form

$$c_{pi}^* = \sum_{j=0}^2 c_{ij} T^j \quad (\text{E1.10})$$

and therefore  $H_i^*$  in Equation (E1.10) is of the form

$$H_i^* = \sum_{j=1}^3 h_{ij} T^j \quad (\text{E1.11})$$

Equation (E1.11) is similar to Equation (E1.4) with  $a_{0i} = a_{4i} = a_{5i}$ .

### Heat Loss Calculation

The heat loss to the overburden and underburden is calculated using the method of [Vinsome and Westerveld \(1980\)](#). They assumed a temperature profile in the overburden and underburden of the form:

$$T(t,z) = (\theta - \theta^0 + b_1 z + b_2 z^2) \exp(-z/d) + \theta^0 \quad (\text{E1.12})$$

where

$T(t,z)$  = over/underburden temperature at time  $t$  at a distance  $z$  from the reservoir boundary

$b_1, b_2$  = time-dependent parameters

$d$  = thermal diffusion length

$\theta$  = temperature in the boundary grid block

$\theta^0$  = initial temperature in boundary grid block

The diffusion length is taken as:

$$d = \frac{\sqrt{\eta t}}{2} \quad (\text{E1.13})$$

where  $\eta$  is the thermal diffusivity

$$\eta = \frac{\kappa_R}{c_R \tilde{\rho}_R} \quad (\text{E1.14})$$

and where

$c_R$  = rock heat capacity

$\tilde{\rho}_R$  = mass density of rock

$\kappa_R$  = rock thermal conductivity

[Vinsome and Westerveld \(1980\)](#) derived the following expression for  $b_1$  and  $b_2$  and the heat loss rate:

$$b_1^{n+1} = \frac{\frac{\eta \Delta t (\theta^{n+1} - \theta^0)}{d^{n+1}} + \xi^n - \frac{(d^{n+1})^3 (\theta^{n+1} - \theta^n)}{\eta \Delta t}}{3(d^{n+1})^2 + \eta \Delta t} \quad (\text{E1.15})$$

$$b_2^{n+1} = \frac{2b_1^{n+1} (d^{n+1}) - (\theta^{n+1} - \theta^0) + \frac{(d^{n+1})^2 (\theta^{n+1} - \theta^n)}{\eta \Delta t}}{2(d^{n+1})^2} \quad (\text{E1.16})$$

$$\xi^n = [(\theta - \theta^0) d + b_1 d^2 + 2b_2 d^3]^n \quad (\text{E1.17})$$

$$Q_{loss} = \kappa_R A \left[ \frac{(\theta^{n+1} - \theta^0)}{d^{n+1}} - b_1^{n+1} \right] \quad (\text{E1.18})$$

where  $A$  is the cross-sectional area for heat loss to the overburden/underburden.

For further information, please refer to [Kenyon and Behie \(1987\)](#), [Peaceman \(1983\)](#), [Peaceman \(1978\)](#), [Peng and Robinson \(1976\)](#), and [Soave \(1972\)](#).

## **2.8 Geochemistry [40 CFR 146.82(a)(6)]**

There are a limited number of wells that penetrate the Mt. Simon Sandstone and, currently, little data to support detailed aqueous or solid phase geochemical modeling for the project. The Mt. Simon Sandstone does contain feldspar, potentially carbon cement, and clay minerals. These minerals are reactive with CO<sub>2</sub>, and it is expected that changes to the aqueous geochemistry of the Mt. Simon Sandstone fluids will occur once CO<sub>2</sub> injection commences.

The computational modeling investigated the effect of mineralization on long-term trapping of CO<sub>2</sub> based on the potential reactions with calcite, anorthite, and kaolinite as part of the PISC Alternative Timeframe using the information currently available (Attachment 9: Post-Injection Site Care, 2022). This modeling demonstrated that mineralization is not expected to play a significant role in trapping for thousands of years. No other geochemical or reactive transport modeling has been completed for the injection zone or the confining zone at this time given the scarcity of data.

The Pre-Operational Testing Program details the data that will be acquired in CCS1 and from the Deep Observation Well (OBS1) that may be used to support future geochemical modeling (Attachment 5: Pre-Op Testing Program, 2022). The mineralogy of the injection zone and confining zone will be determined through a combination of core analysis and well logging. Well log data will also be acquired through the lowermost USDW and ACZ monitoring zone to assist in establishing the mineralogy of these formations.

Fluid samples will be acquired from the lowermost USDW, the ACZ monitoring interval, and the injection zone when the project wells are drilled. The Testing and Monitoring Plan details the parameters and analytes that will be used to establish baseline conditions for these formations as well as during the injection phase of the project (Attachment 7: Testing And Monitoring, 2022). The aqueous geochemistry data gathered during the pre-operational phase of the project will also be used to support future geochemical modeling work. Geochemical modeling will likely focus on reactions in the injection zone and any reactions in the confining zone that may impact long-term containment and endangerment of USDWs.

## **2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)**

The Pre-Operational Testing Program presents the data that will be collected in order to determine and verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the injection zone, confining zone, and other relevant geologic formations via petrophysical logging and analysis, and core acquisition and testing (Attachment 5: Pre-Op Testing Program, 2022). In addition, baseline 3D surface seismic data will be acquired during the pre-injection phase of the project to assist in characterizing injection zone and confining zone rock properties away from CCS1 and OBS1.

At this time, the project does not plan to acquire baseline atmospheric or soil gas data nor are there plans to pursue atmospheric or soil gas monitoring during the injection phase of the project.

## **2.10 Site Suitability [40 CFR 146.83]**

The AK Steel and INEOS (BP Lima) disposal wells provided useful data on the Eau Claire Formation and Mt. Simon Sandstone and were used as analogs for this project. In addition, study of other regional well data and computational modeling indicate that the geologic setting of the proposed injection zone has the capacity to store 13.5 million metric tons of CO<sub>2</sub> over 30 years of injection based on:

### ***1.1.2 Computational Model***

Numerical simulation of carbon dioxide (CO<sub>2</sub>) injection into deep geologic formations requires the modeling of complex, coupled hydrologic, chemical, and thermal processes including multi-fluid flow and transport, partitioning of CO<sub>2</sub> into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. The fluid flow model used for this application is Generalized Equation Model (GEM), a commercial simulator developed by Computer Modelling Group (CMG) of Calgary, Alberta.

GEM has been developed by CMG over many years primarily for modeling hydrocarbon reservoirs. This simulation software was selected because it has many advanced features for carbon sequestration modeling including relative permeability hysteresis, CO<sub>2</sub> solubility in water, water vaporization, geochemistry, mineralization, thermal, and geomechanical properties.

For this application, an equation of state (EOS) was developed with three components: CO<sub>2</sub>, methane (CH<sub>4</sub>), and water (H<sub>2</sub>O). Since the computational model was originally designed for hydrocarbon reservoirs, it requires a hydrocarbon component (CH<sub>4</sub>), but it is only present as a trace component. The phases modeled are supercritical CO<sub>2</sub>, dissolved CO<sub>2</sub> in water, residual CO<sub>2</sub> (gas trapping), and CO<sub>2</sub> trapped by mineralization.

The model uses well established discretized fluid flow equations and an adaptive-implicit method for solving the resulting sparse matrix. Details can be found in the following publications: (Collins, D.A., Nghiem, L.X., Li, Y.-K. and Grabenstetter, J.E., May 1992), (Thomas, G.W. and Thurnau, D.H., October 1983), (Nghiem, L.X. and Li, Y.-K., September 4-8, 1989)

The model uses a cubic EOS with Peng-Robinson (PR) coefficients. Viscosity modeling is accomplished by using either the Jossi-Stiel-Thodos or Pedersen correlations. Key assumptions include:

- Eccentricity of molecules
- Use of random mixing rules
- Binary interaction parameter
- Minimum Gibbs energy as an equilibrium criterion
- Fugacity as a function of measurable properties
- Volume translation used to improve density prediction

The processes that were modeled for this application are:

- Convective and dispersive flow
- Relative permeability hysteresis
- Gas solubility in aqueous phase
- H<sub>2</sub>O vaporization
- Mineralization

It is also possible to assess the confining layer integrity using geomechanics. An initial evaluation was conducted using data from the literature; this evaluation will be updated when data from the injection or monitoring wells has been acquired.

Table 3 describes all of the processes used in the computational modeling to model CO<sub>2</sub> trapping within the injection zone. All of these primary processes were included in the initial model. No new mechanisms are anticipated.

**Table 3: Processes captured in the computational modeling**

<b>Computational Modeling Processes</b>	<b>Description</b>
Convective Flow	Movement of CO <sub>2</sub> through the pore space during the injection period
Dispersive Flow	Result of gravity segregation and increasing CO <sub>2</sub> solubility in water
Relative Permeability Hysteresis	Trapping of CO <sub>2</sub> in pore spaces as a result of imbibition (increase in wetting phase saturation), which occurs during gravity segregation
CO <sub>2</sub> Solubility	Modeled by a modified form of Henry's law
H <sub>2</sub> O Vaporization	Can occur around the wellbore as a result of high gas velocities and can lead to salt precipitation
Mineralization	Long-term trapping mechanism that occurs over thousands of years

The computational model is a subset of the static model, as it is not required to be as laterally extensive. The computational model is 7.9 miles (east-west) by 7.9 miles (north-south) and uses smaller 100 ft cells for horizontal gridding. The vertical layering remained consistent. The computational modeling focused on the Eau Claire Shale and the Mt Simon Sandstone.

## **1.2 Site Geology and Hydrology**

All information regarding the site geology and hydrology are provided in the Project Narrative (Attachment 1: Narrative, 2022). This includes the associated figures such as geologic maps, hydrologic maps, cross sections, and local stratigraphic columns.

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## 2.5 Geomechanical and Petrophysical Information [40 CFR 146.82 (a)(3)(iv)]

### 2.5.1 Geomechanics

Simple geomechanical modeling was completed to test the integrity of the confining zone. The computation modeling results were used as input to for the geomechanical modeling (Attachment 2: AoR and Corrective Action, 2022). Geomechanical information for the Eau Claire and Mt. Simon formations was found in the INEOS (BP Lima) Class I permit (Table 11). The average values were used to model the Eau Claire confining zone integrity given the anticipated injection rate of 400 kt/Y. In addition, step-rate test data and information on the breakdown, propagation, and closure gradients were obtained from this permit to support the modeling of the confining zone integrity (Figure 30 and Table 12).

**Table 11: Summary of Young's Modulus, Poisson's Ratio, and Bulk Compressibility values from the INEOS (BP Lima) Nitriles UIC permit (INEOS USA, LLC, 2015).**

Horizon	Young's Modulus (psi)	Poisson's Ratio	Bulk Compressibility (1/psi)
Cincinnati Group	2.17E+06	0.14	5.35E-07
Trenton	6.51E+06	0.06	3.19E-07
Black River	6.88E+06	0.09	3.48E-07
Knox (KD2)	1.06E+07	0.10	2.67E-07
Knox (KD1)	5.39E+06	0.19	3.59E-07
Knox Average	7.67E+06	0.14	3.06E-07
Eau Claire (EC4)	1.78E+06	0.01	1.41E-07
Eau Claire (EC3)	4.19E+06	0.11	5.40E-07
Eau Claire (EC2)	3.61E+06	0.25	5.17E-07
Eau Claire (EC1)	2.65E+06	0.11	4.25E-07
Eau Claire Average	5.65E+06	0.12	5.60E-07
Mt. Simon (MS3)	2.62E+06	0.11	1.06E-06
Mt. Simon (MS2)	2.50E+06	0.17	6.95E-07
Mt. Simon (MS1)	2.39E+06	0.13	1.06E-06
Mt. Simon Average	2.46E+06	0.14	1.07E-06
Middle Run	5.26E+06	0.11	7.85E-07

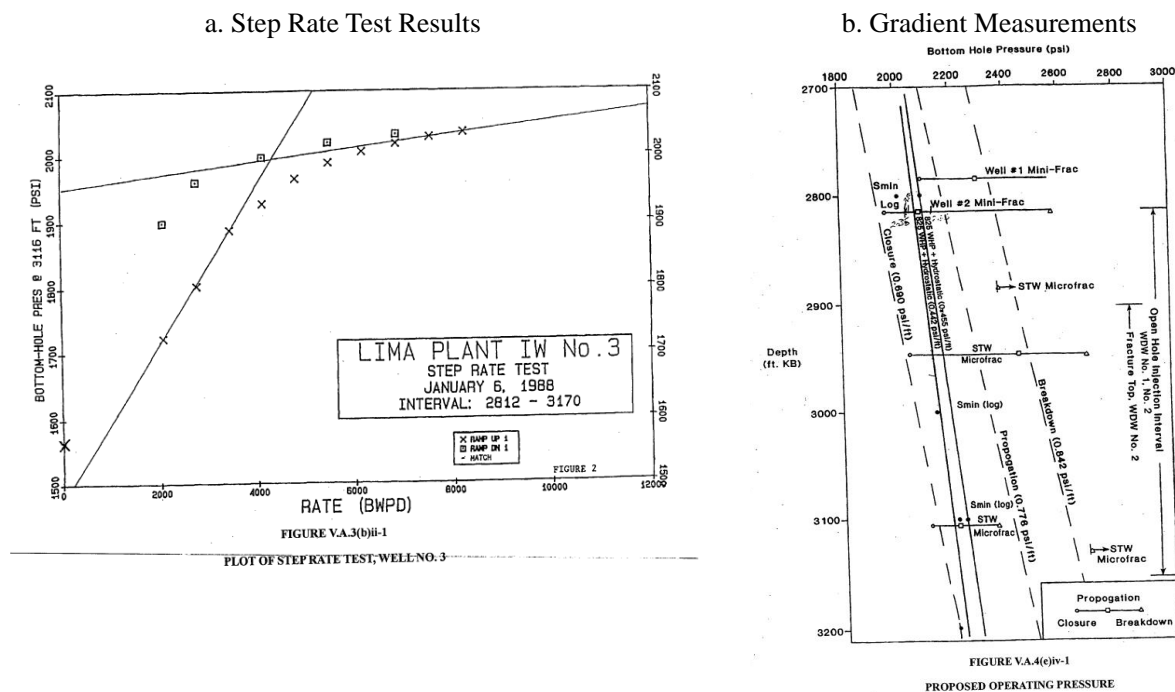


Figure 30: Geomechanical data from the INEOS (BP Lima) Nitriles disposal site. A. step rate test results b. breakdown, propagation, and closure gradients (INEOS (BP Lima) Nitriles, August 22, 2016)

Table 12: Summary of breakdown, propagation, and closure gradients and pressures for the top of the Mt. Simon Sandstone at 3,100 ft based on the INEOS (BP Lima) Nitriles permit (INEOS (BP Lima) Nitriles, August 22, 2016)

	Gradient (psi/ ft)	Pressure (psia)
Breakdown	0.842	2,610
Propagation	0.776	2,406
Closure	0.690	2,139

The geomechanical modeling predicted an initial mean effective stress of 795 and 966 psi for the tops of the Eau Claire Formation and Mt. Simon Sandstone, respectively. It also predicts a maximum increase in pore pressure of 378 psi at the top of the Mt. Simon Sandstone, which is below the pressures required to open fractures within the Eau Claire Shale. It also showed no evidence of CO<sub>2</sub> migration into the Eau Claire Shale after 30 years of injection. Even at injection rates of 1.9 MMT/yr, the decrease in effective stress on the confining zone was not enough to open existing fractures.

During the pre-operational phase of the project, a variety of site-specific data from the confining and injection zones will be acquired in the project wells to support further geomechanical modeling. These data include:

- Caliper and image logs,
- Triaxial testing to establish geomechanical parameters such as rock strength, Young's Modulus, Poisson's Ratio, and fracture gradient,
- Step-rate testing.

This document describes how the geologic and hydrologic information were used to delineate the Area of Review (AoR). It also addresses the extent to which the Hoosier #1 Project needs to undertake corrective actions for features within the AoR that may penetrate the confining zone, and how such corrective actions will be taken if needed in the future. Section 1.1 describes the computational model that was used to delineate the AoR, including a description of the simulator and the physical processes modeled and a description of the conceptual model and numerical implementation. It also describes the AoR, and how the AoR will be re-evaluated over time. Section 4 describes the Hoosier #1 Project Corrective Action Plan. This document is intended to demonstrate compliance with 40 CFR 146.84.

## 1 Computational Modeling Approach (40 CFR 146.84(b)(1))

### 1.1 Model Background

#### 1.1.1 Static Model

The Hoosier#1 project made use of two models (Figure 1). The first was a static model which incorporated local and regional data in a single model. The second was a smaller computational model. The model was developed using Rock Flow Dynamics' software tNavigator. Table 1 summarizes the steps and the workflow used to generate the final structural and static model.

**Table 1: Summary of static modeling steps**

Modeling Step	Input Data	Information
Injection and Confining Zone Details	<ul style="list-style-type: none"> <li>Core data from nine wells and well log data were downloaded from public data sources</li> <li>Class I injection wells were used as calibration points</li> </ul>	<ul style="list-style-type: none"> <li>Facies, porosity, and permeability of the Eau Claire Formation and Mt. Simon Sandstone</li> <li>Petrophysical properties</li> </ul>
Incorporate two-dimensional (2D) Seismic Survey	<ul style="list-style-type: none"> <li>Three 2D surface seismic lines</li> </ul>	<ul style="list-style-type: none"> <li>Local detail of geologic structures</li> </ul>
Formation Surfaces and Thickness	<ul style="list-style-type: none"> <li>Well logs</li> </ul>	<ul style="list-style-type: none"> <li>Regional geologic structure</li> </ul>
Static Model	<ul style="list-style-type: none"> <li>Data above</li> </ul>	<ul style="list-style-type: none"> <li>Develop a model to represent subsurface facies, porosity, and permeability</li> </ul>
Computational Model	<ul style="list-style-type: none"> <li>Static model</li> </ul>	<ul style="list-style-type: none"> <li>CO<sub>2</sub> and pressure plume behavior</li> </ul>

The formations or zones that were modeled and the number of layers in each zone have been summarized in Table 2. Figure 2 and Figure 3 show the stratigraphic column of horizons while Figure 2 and Figure 4 displays the zones used in the static model. The deepest underground source of drinking water (USDW) is plotted on these cross sections and is discussed in detail in the Project Narrative (Attachment 1: Narrative, 2022).

The static model was 141 miles (east-west) by 116 miles (north-south). The area was selected to include wells in the region that had reliable petrophysical data. The model contains 24.4 million cells. The static model cell size was selected to represent the subsurface heterogeneity and keep the cell count small enough to manageably run the computational modeling. Thinner cells were used in the injection zone where the computational modeling was focused on the CO<sub>2</sub> injection.

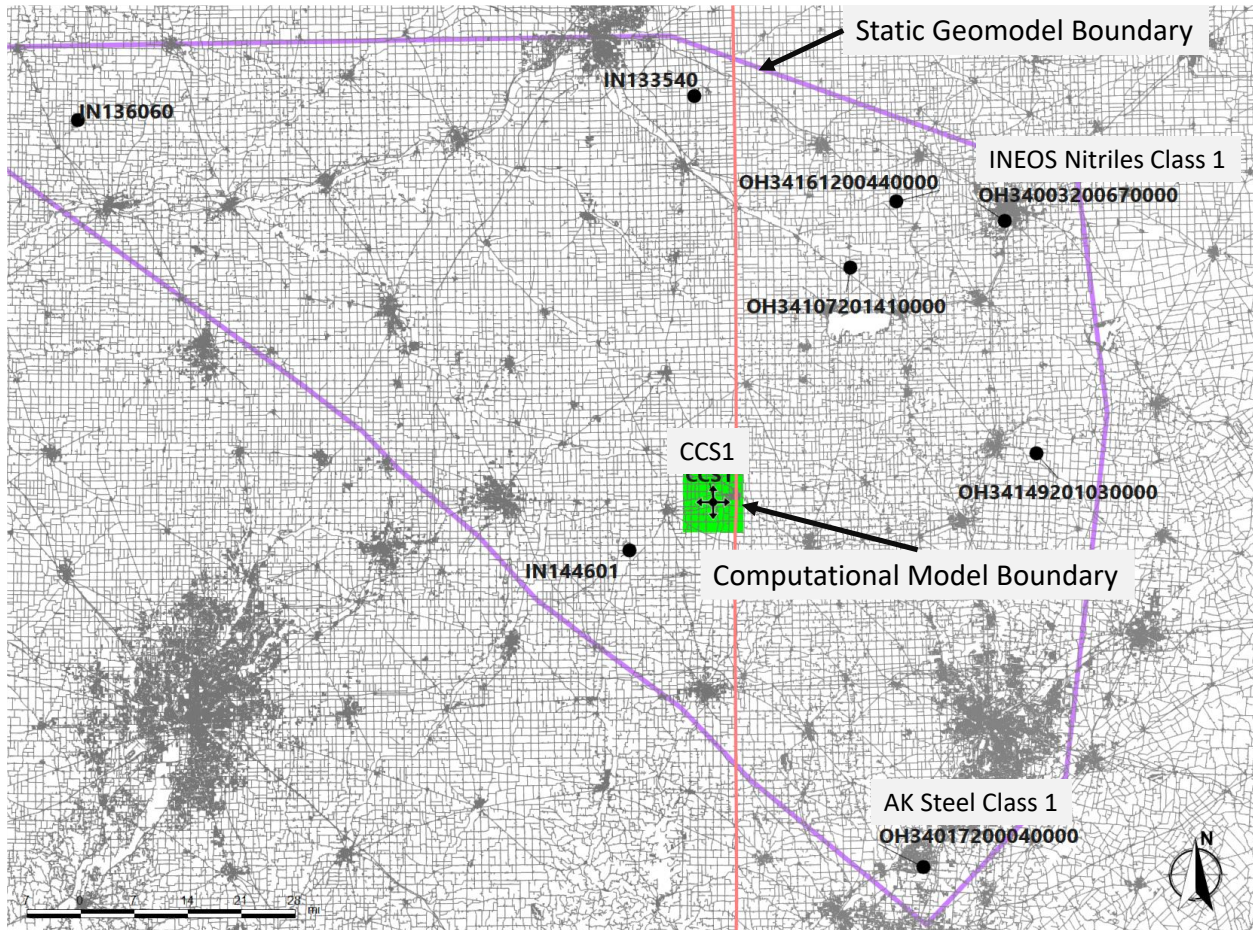


Figure 1: Areas covered by the static and computational models

**Table 2: Table of static model formations**

<b>Formation (Zone)</b>	<b>Layer Type</b>	<b>Number of Model Layers</b>	<b>X-Y Cell Length</b>	<b>Porosity and Permeability Data Source</b>
Undifferentiated	Proportional	1	500ft	Not modeled
Trenton Limestone		1		Not modeled
Knox Formation		1		Not modeled
Davis Formation		1		Not modeled
Eau Claire Formation		150		Well logs and Class I wells
Mt Simon Sandstone		125		Well logs and Class I wells
Precambrian Basement		40		Not modeled

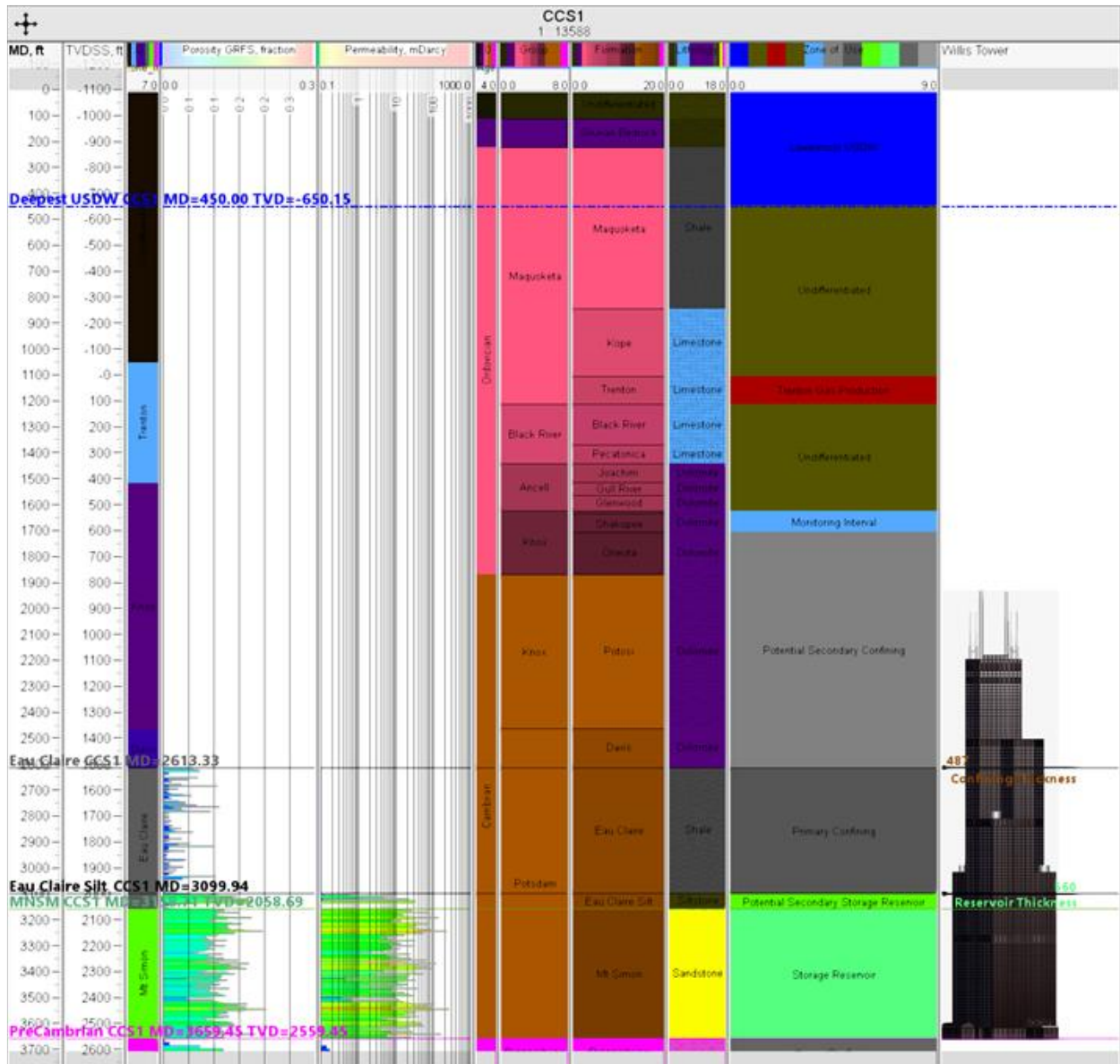


Figure 2: CCS1 modeling stratigraphic column

Plan revision number: N/A  
 Plan revision date: July 4, 2022

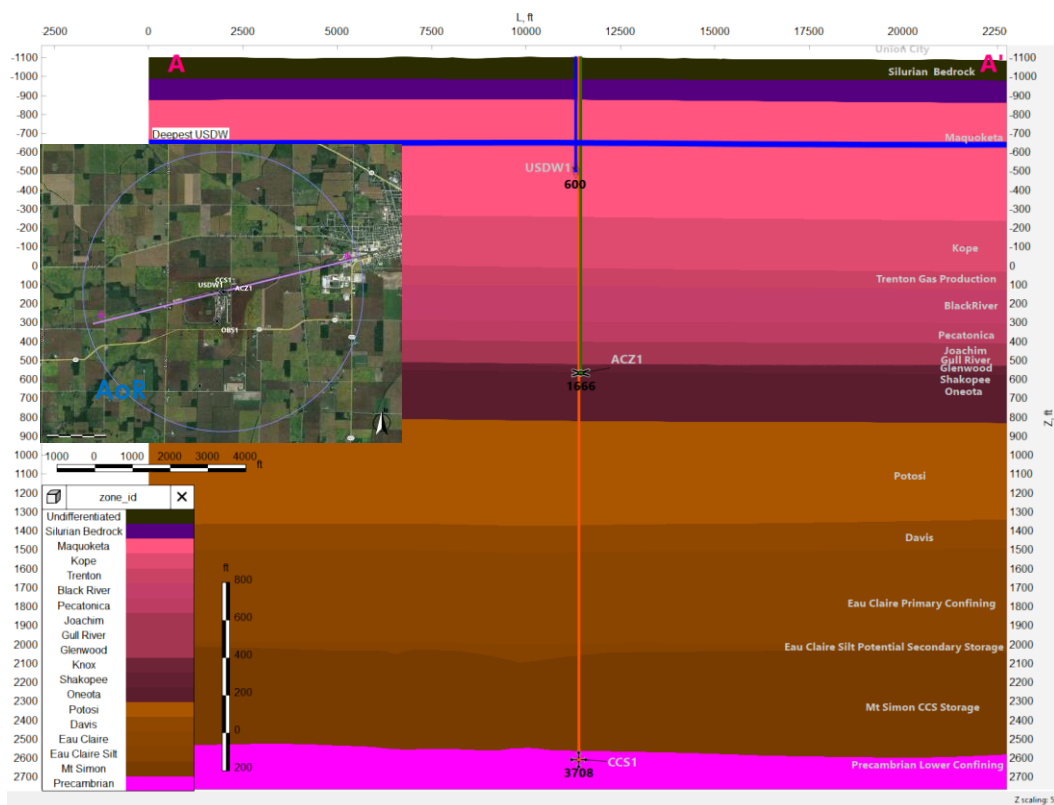


Figure 3: Cross Section A-A' stratigraphic formations.

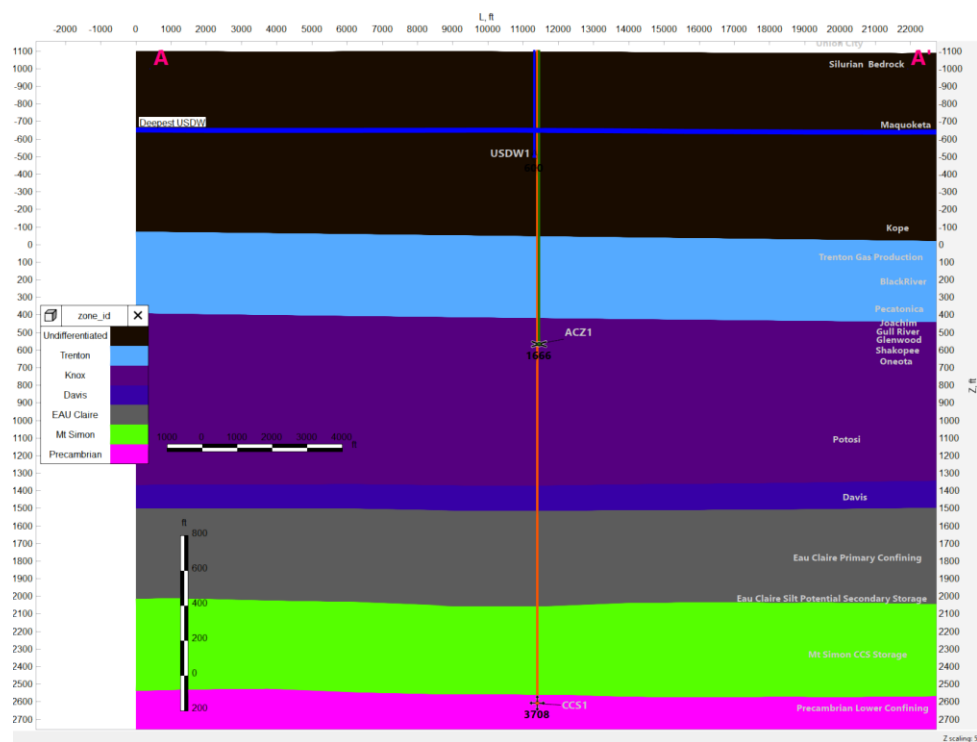


Figure 4: Cross Section A-A' static model formations.

### ***1.1.2 Computational Model***

Numerical simulation of carbon dioxide (CO<sub>2</sub>) injection into deep geologic formations requires the modeling of complex, coupled hydrologic, chemical, and thermal processes including multi-fluid flow and transport, partitioning of CO<sub>2</sub> into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. The fluid flow model used for this application is Generalized Equation Model (GEM), a commercial simulator developed by Computer Modelling Group (CMG) of Calgary, Alberta.

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For this application, an equation of state (EOS) was developed with three components: CO<sub>2</sub>, methane (CH<sub>4</sub>), and water (H<sub>2</sub>O). Since the computational model was originally designed for hydrocarbon reservoirs, it requires a hydrocarbon component (CH<sub>4</sub>), but it is only present as a trace component. The phases modeled are supercritical CO<sub>2</sub>, dissolved CO<sub>2</sub> in water, residual CO<sub>2</sub> (gas trapping), and CO<sub>2</sub> trapped by mineralization.

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The processes that were modeled for this application are:

- Convective and dispersive flow
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- Gas solubility in aqueous phase
- H<sub>2</sub>O vaporization
- Mineralization

It is also possible to assess the confining layer integrity using geomechanics. An initial evaluation was conducted using data from the literature; this evaluation will be updated when data from the injection or monitoring wells has been acquired.

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H <sub>2</sub> O Vaporization	Can occur around the wellbore as a result of high gas velocities and can lead to salt precipitation
Mineralization	Long-term trapping mechanism that occurs over thousands of years

The computational model is a subset of the static model, as it is not required to be as laterally extensive. The computational model is 7.9 miles (east-west) by 7.9 miles (north-south) and uses smaller 100 ft cells for horizontal gridding. The vertical layering remained consistent. The computational modeling focused on the Eau Claire Shale and the Mt Simon Sandstone.

## **1.2 Site Geology and Hydrology**

All information regarding the site geology and hydrology are provided in the Project Narrative (Attachment 1: Narrative, 2022). This includes the associated figures such as geologic maps, hydrologic maps, cross sections, and local stratigraphic columns.

### 1.3 Model Domain

Model domain information is summarized in Figure 1, Table 4, and Table 5.

**Table 4: Static Model domain information.**

Static Model Domain Information			
Coordinate System	Indiana East European Petroleum Survey Group (EPSG) 2965		
Horizontal Datum	Indiana East EPSG 2965		
Coordinate System Units	feet		
Zone	Indiana East EPSG 2965		
FIPZONE	-	ADZONE	-
Coordinate of X min	57216	Coordinate of X max	824716
Coordinate of Y min	1511167	Coordinate of Y max	2123667
Elevation of bottom of domain (fbsl)	3967	Elevation of bottom of domain	-1187

**Table 5: Computational Model domain information.**

Computational Model Domain Information			
Coordinate System	Indiana East EPSG 2965		
Horizontal Datum	Indiana East EPSG 2965		
Coordinate System Units	feet		
Zone	Indiana East EPSG 2965		
FIPZONE	-	ADZONE	-
Coordinate of X min	530951	Coordinate of X max	572951
Coordinate of Y min	1778776	Coordinate of Y max	1820776
Elevation of bottom of domain (fbsl)	2681	Elevation of bottom of domain	1926

A horizontal grid cell size of 500 feet (ft) was used. For the vertical cell size, proportional layering was used to generate cells approximately 4 ft high. The static model included horizons from ground level to the model base below the Precambrian horizon (Figure 4). Property modeling was focused on the Eau Claire Shale confining zone and the Mt Simon Sandstone injection zone.

### 1.4 Porosity and Permeability

#### 1.4.1 Petrophysical Well Log Upscaling

The Project Narrative includes a discussion of the wells in the region that provided important porosity and permeability data for the project as well as the petrophysical analysis that was completed on these wells (Attachment 1: Narrative, 2022). The well log data was upscaled and distributed into the static model.

The critical delta pressure is the increase in pressure necessary for injection zone fluids to reach the lowermost USDW through a conduit, such as an old wellbore that penetrates the injection zone. Although this is a highly unlikely event, the AoR is established using this criteria and all wellbores in the area that penetrate the injection zone are identified and reported.

Calculation of Critical Delta Pressure for Pressure Plume Determination:

$$\Delta P_{if} = P_u + \rho_{ig} \cdot (z_u - z_i) - P$$

Where,

$\Delta P_{if}$  = Critical Delta Pressure for Pressure Plume = 227 psi

$P_u$  = USDW Initial Pressure = 171 psia

$\rho_{ig}$  = Injection Zone Fluid Gradient = 0.465 psi/ft

$z_u$  = Elevation of USDW = 450'

$z_i$  = Elevation of Injection Zone = 3,114'

$P$  = Injection Zone Initial Pressure = 1,183 psia

The static model was 141 miles (east-west) by 116 miles (north-south). The area was selected to include wells in the region that had reliable petrophysical data. The model contains 24.4 million cells. The static model cell size was selected to represent the subsurface heterogeneity and keep the cell count small enough to manageably run the computational modeling. Thinner cells were used in the injection zone where the computational modeling was focused on the CO<sub>2</sub> injection.

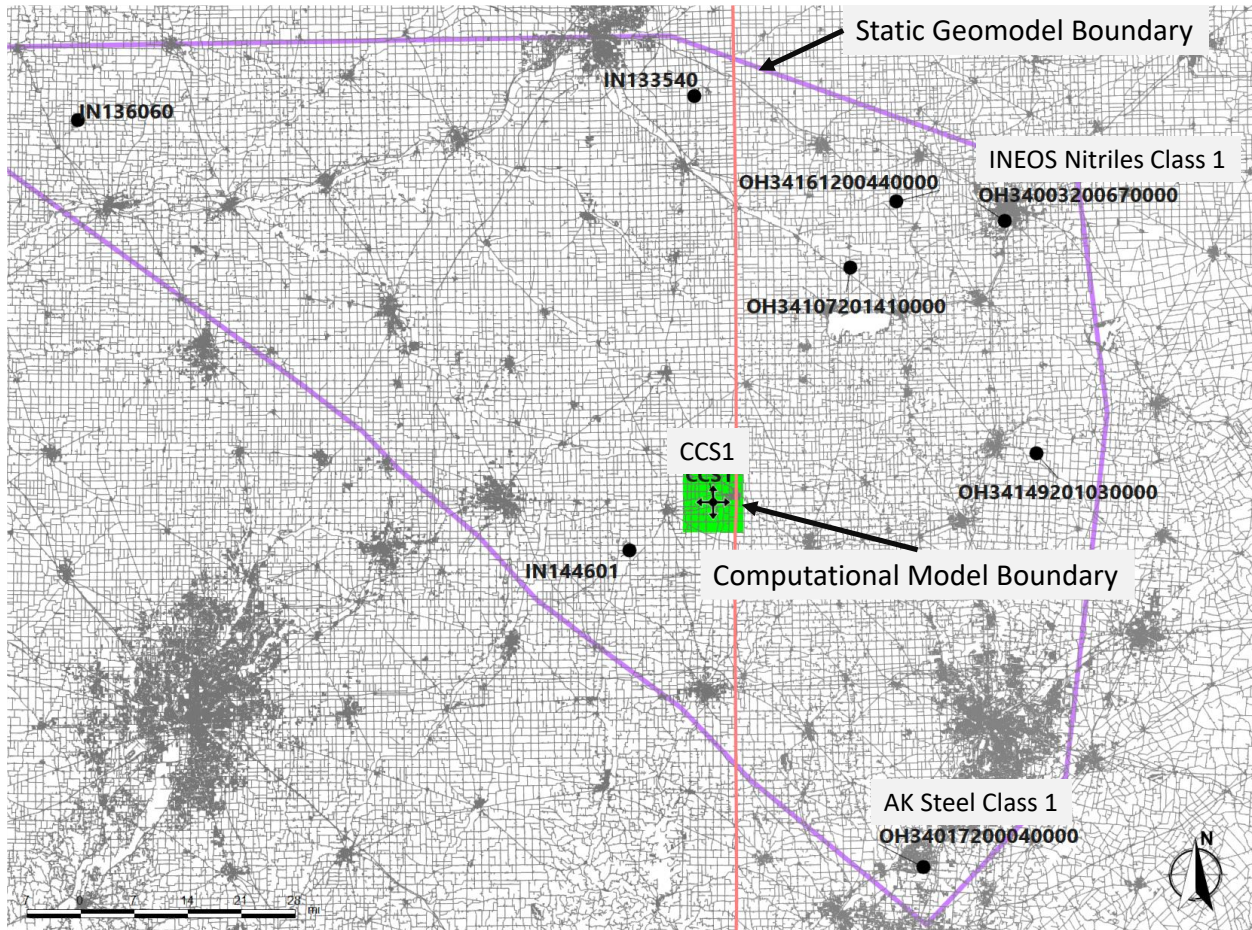


Figure 1: Areas covered by the static and computational models

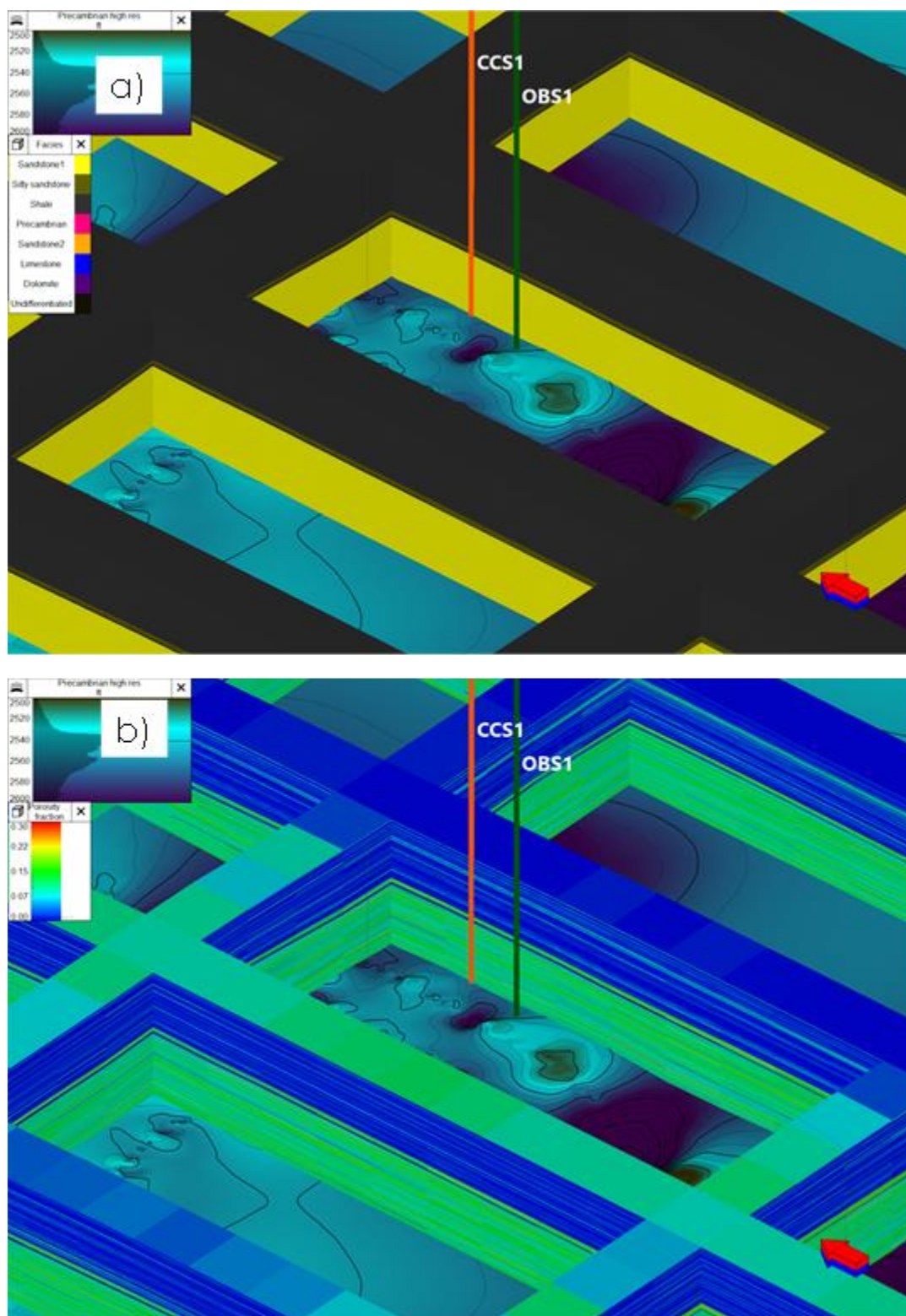


Figure 9: 3D view of static model showing a) facies, b) effective porosity.

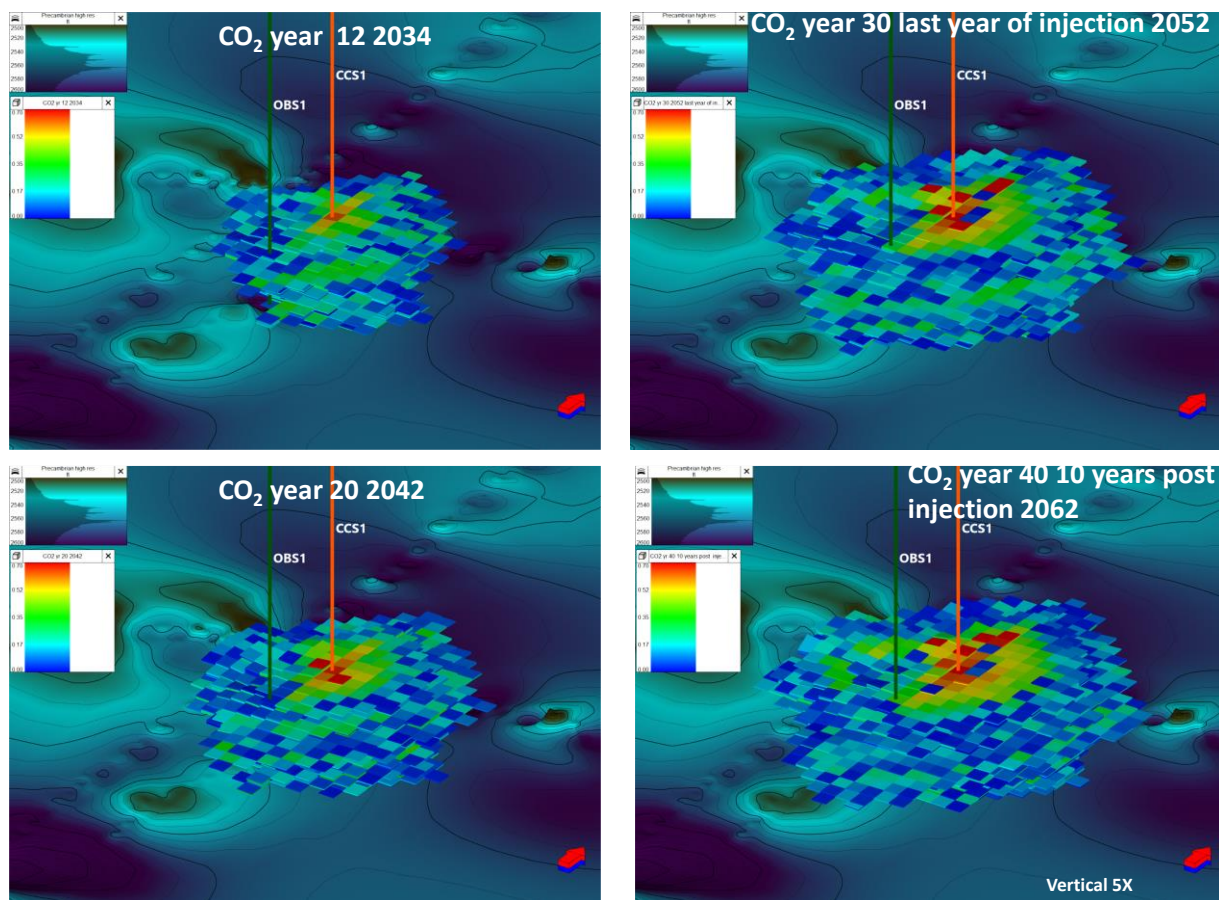
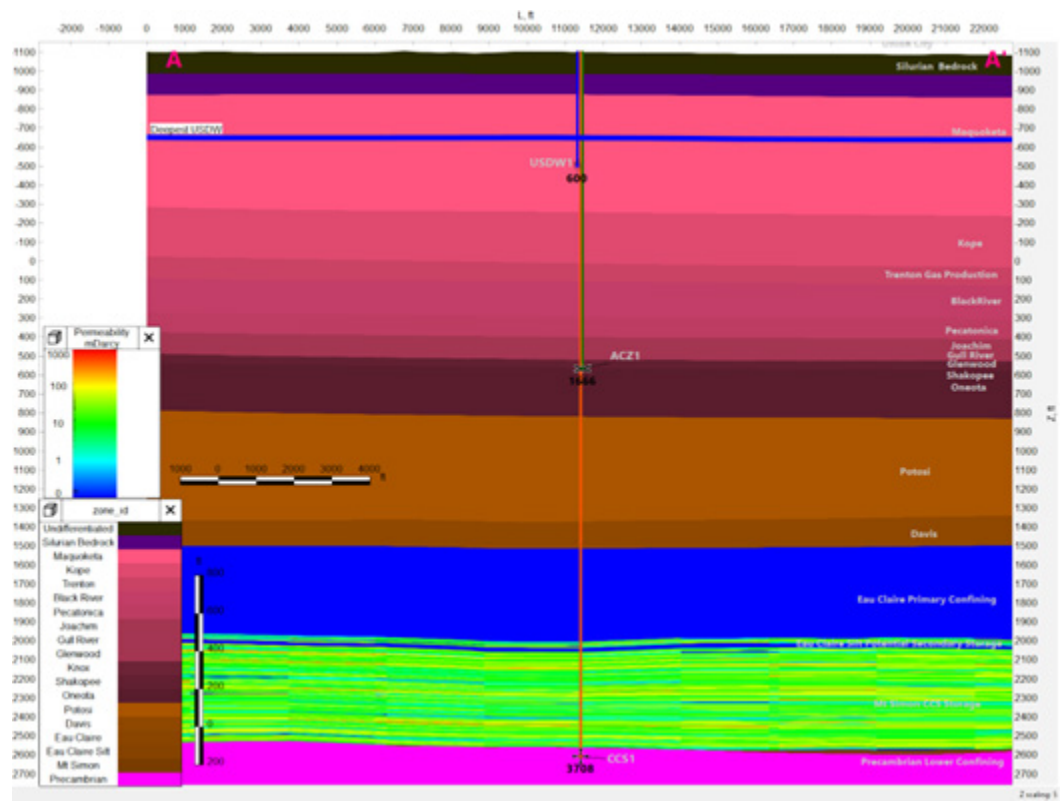


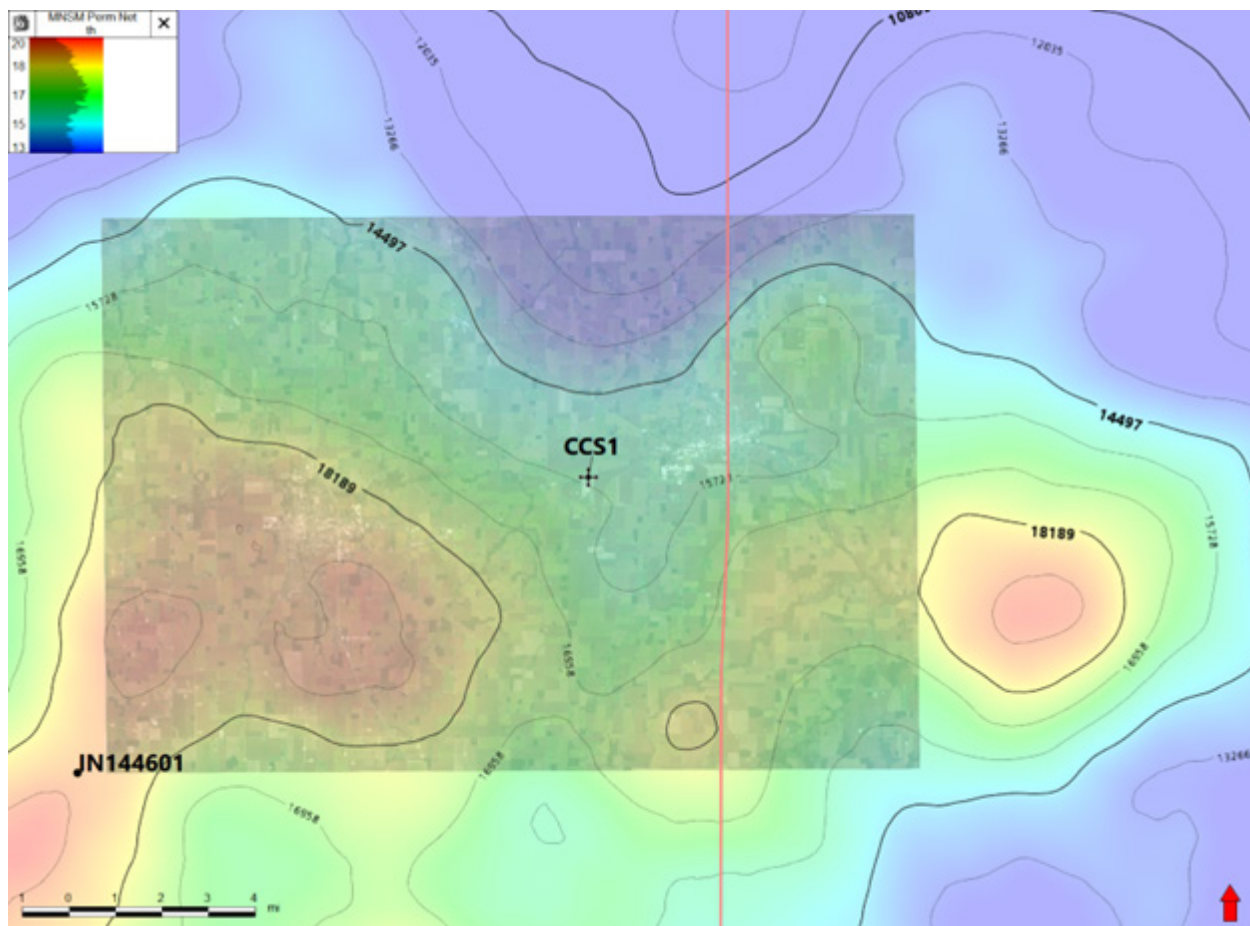
Figure 21: Time-lapse CO<sub>2</sub> plume development in 3D space.

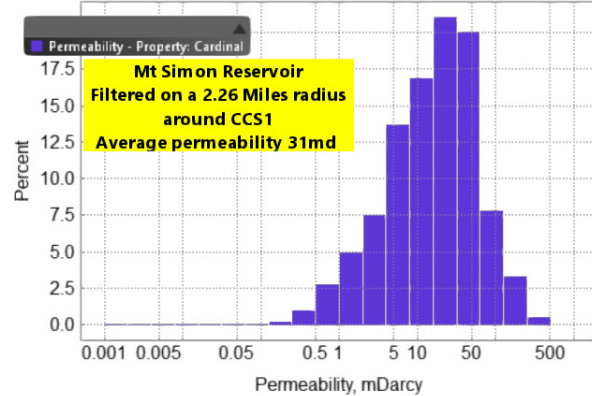
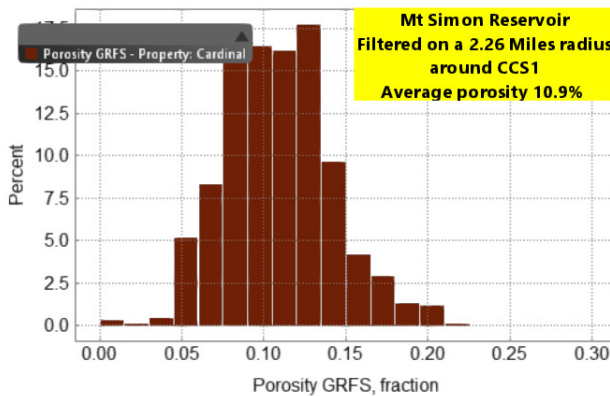
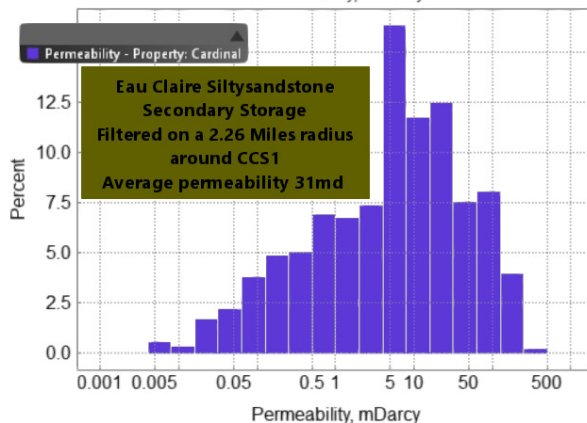
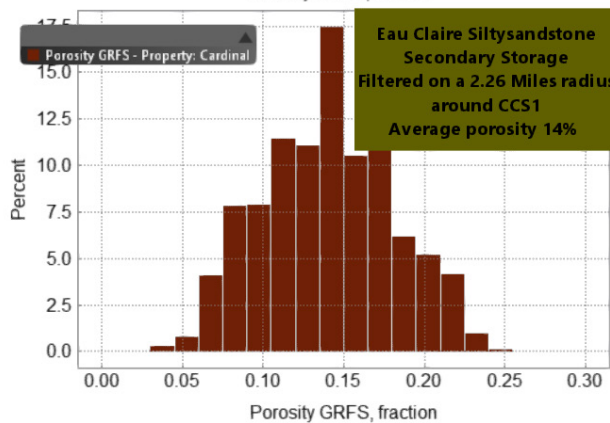
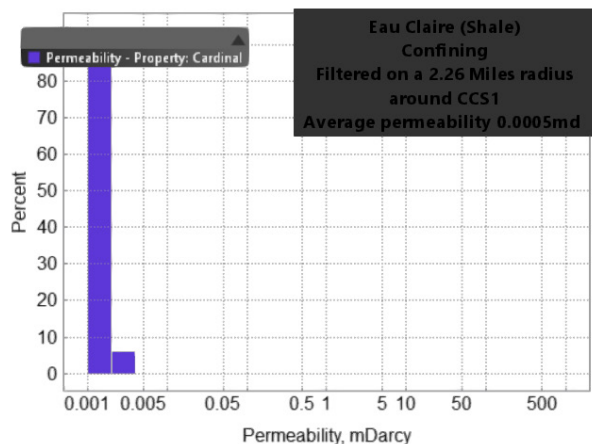
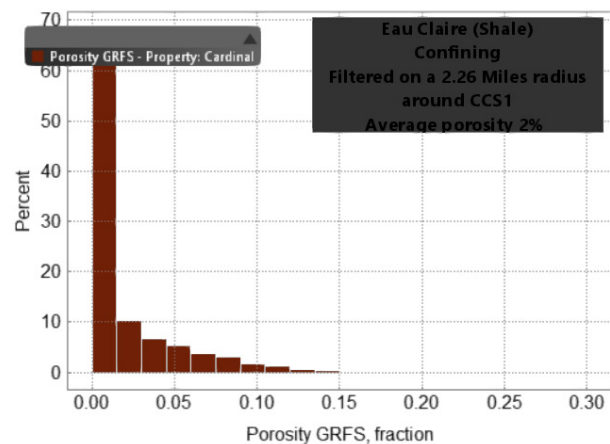
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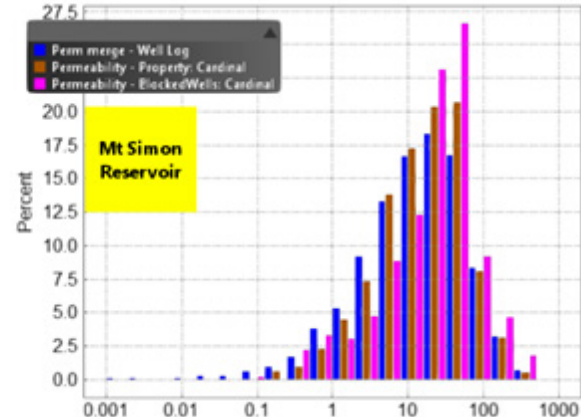
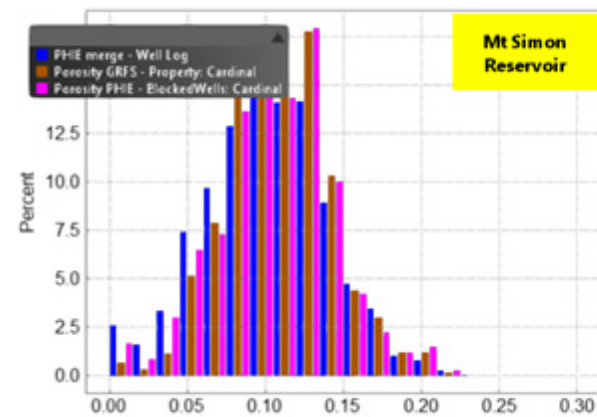
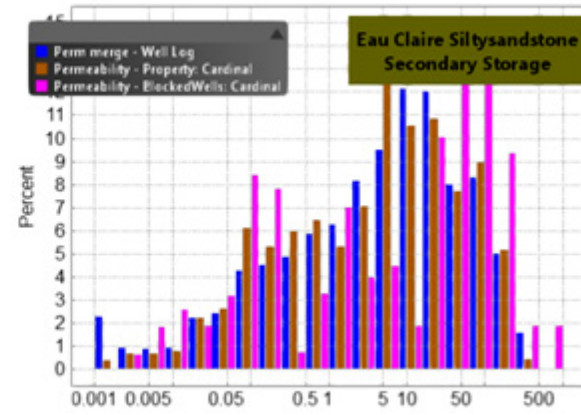
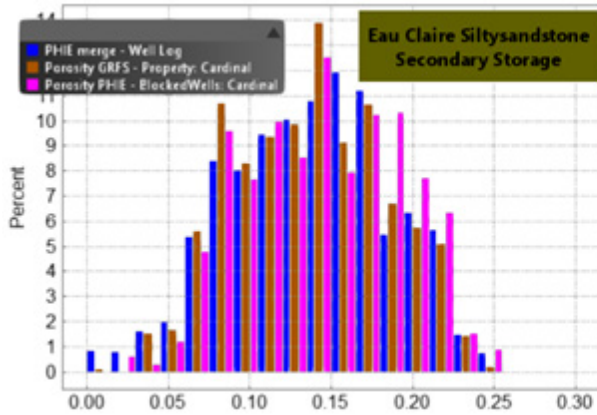
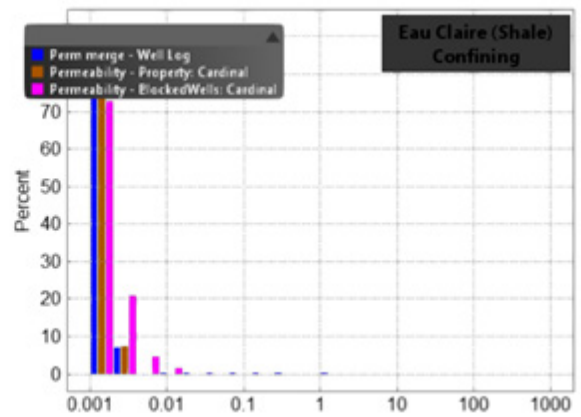
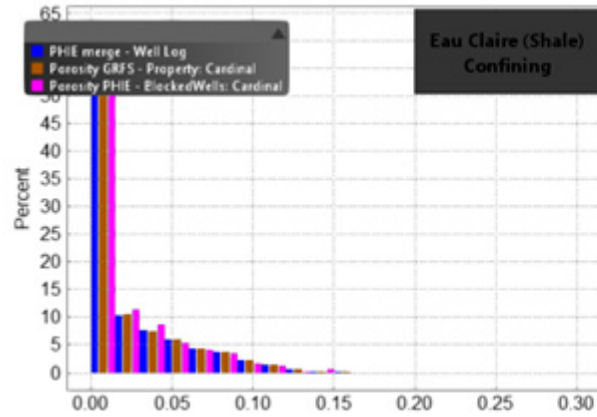
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**Figure 5: Confidential Business Information: Well log upscaling.**

**Figure 6: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey).**

### ***1.4.2 Facies and Petrophysical Modeling***

The upscaled core porosity from the nine wells provided high vertical resolution at each well for the static model; however, little was known about the porosity values between the wells. Therefore, variogram analysis was used to interpolate the data from the wells into the interwell space such that porosity represented the geological setting.

Facies were interpolated using the tNavigator Amazonas (Degterev, 2020) process that proved to be a reliable way to interpolate these facies data at these distances (Figure 7). The facies of the Eau Claire Formation consisted of primary shale with a thin layer of silty sandstone at the base which was modeled here to represent the Eau Claire Silt (potential secondary sequestration). The facies of the Mt Simon Sandstone were interpolated with two sandstone facies (Sandstone\_1 and Sandstone\_2). In the Precambrian, one facies was used. Figure 7 shows the facies thickness maps within the Mt Simon Sandstone and the Eau Claire Formation.

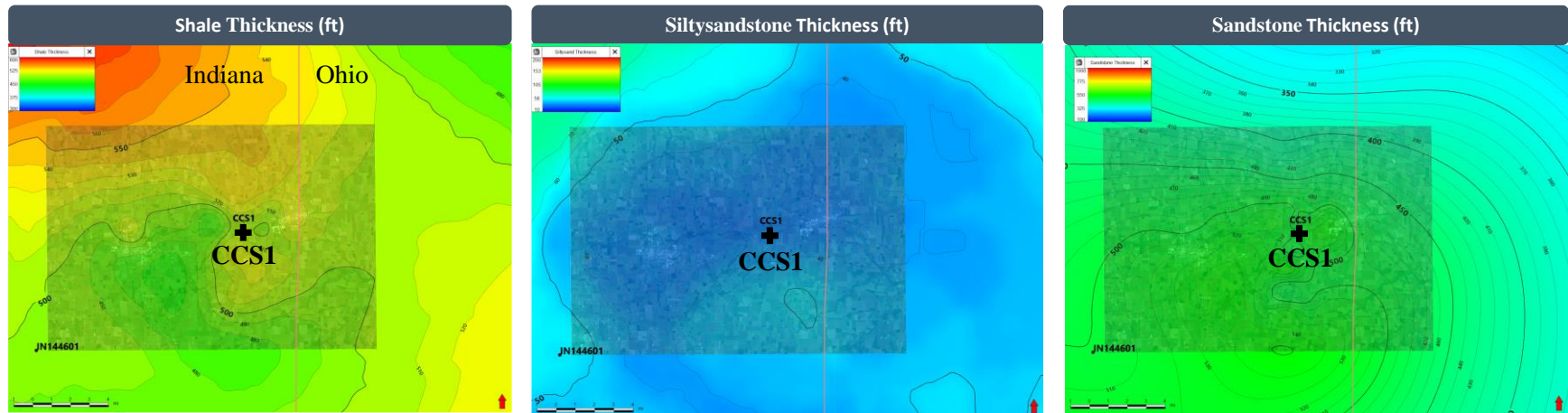


Figure 7: Facies thickness maps within the Mt. Simon Sandstone and Eau Claire Formation.

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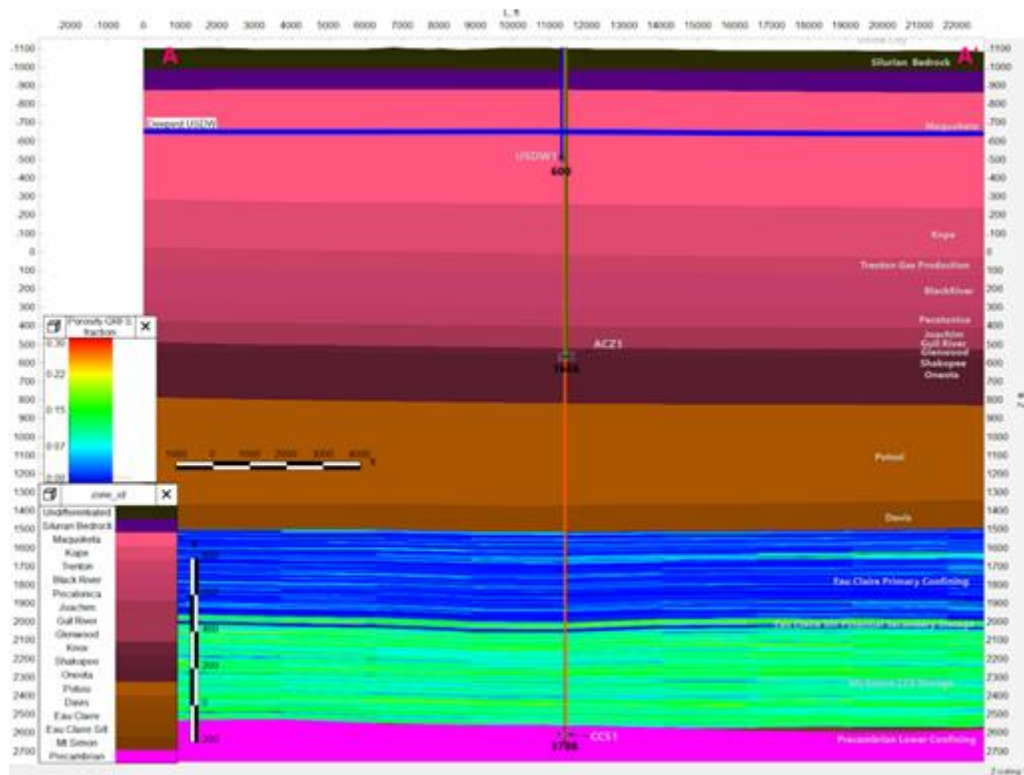


Figure 8: Cross Section A-A' formations and static model effective porosity.

The equations derived from Figure 6 were used to determine the effective porosity and permeability based on facies type (Figure 8 and Figure 10). The flow capacity of the injection zone can be characterized by the permeability-height product (kh) (Figure 11). The kh of the AoR compares favorably to the kh calculated from the fall-off test (FOT) reported in the INEOS (BP Lima) Nitrile disposal wells (INEOS USA LLC, 2015).

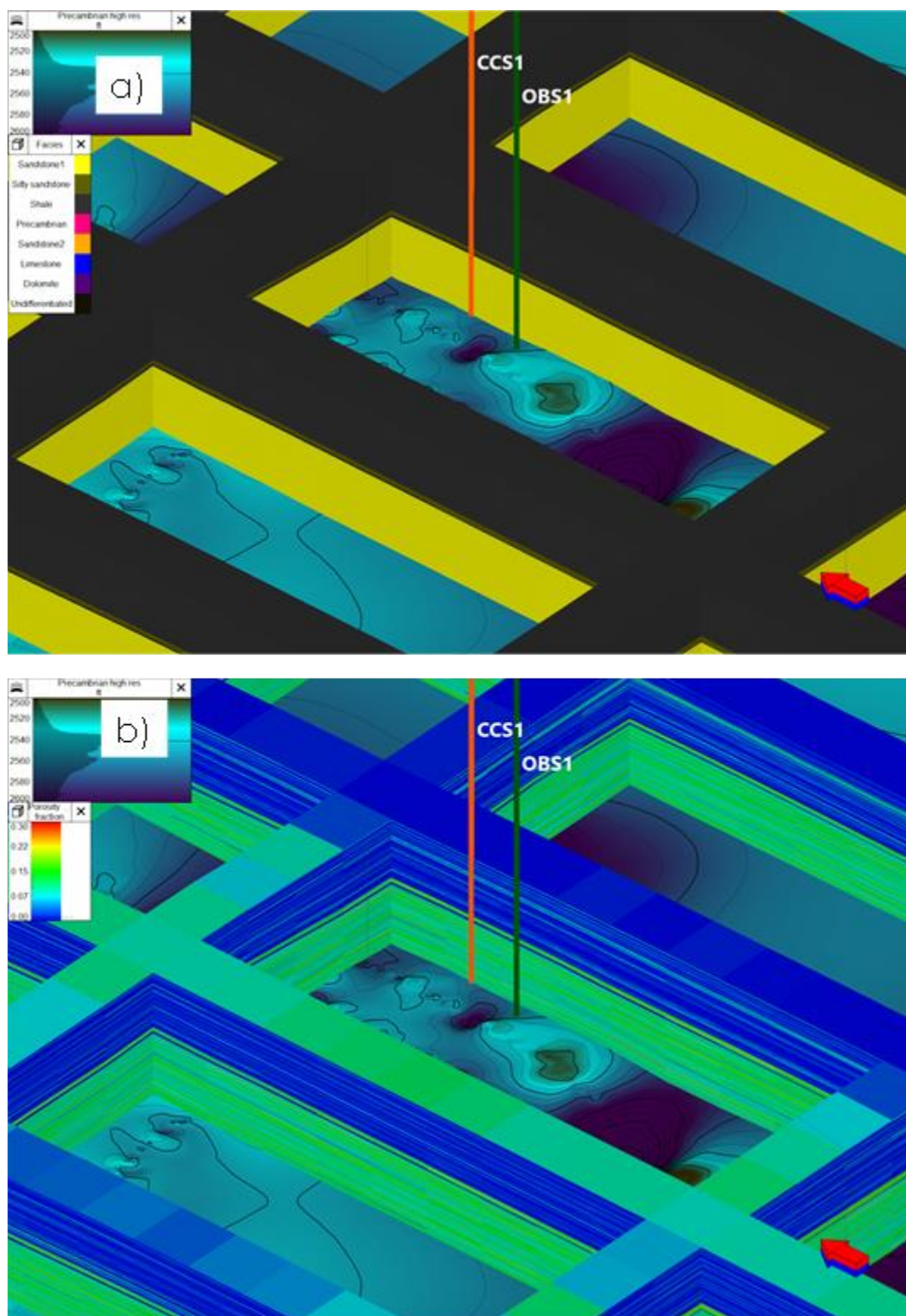


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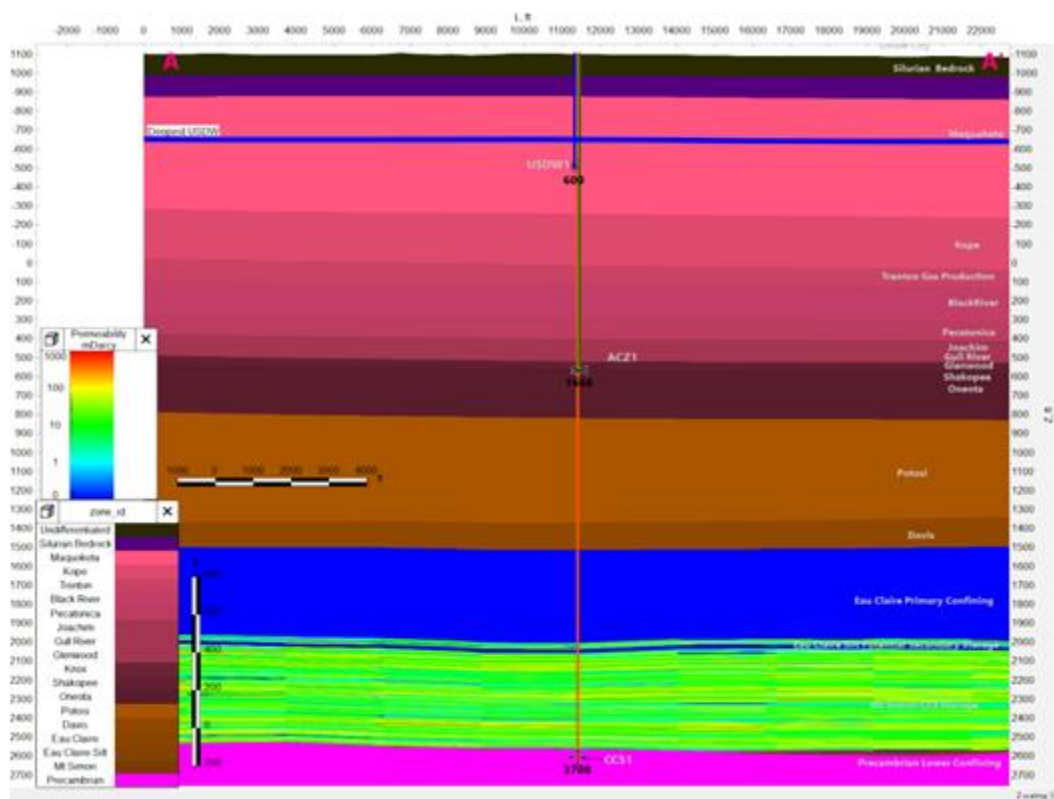


Figure 10: Cross Section A-A' formations and static model permeability.

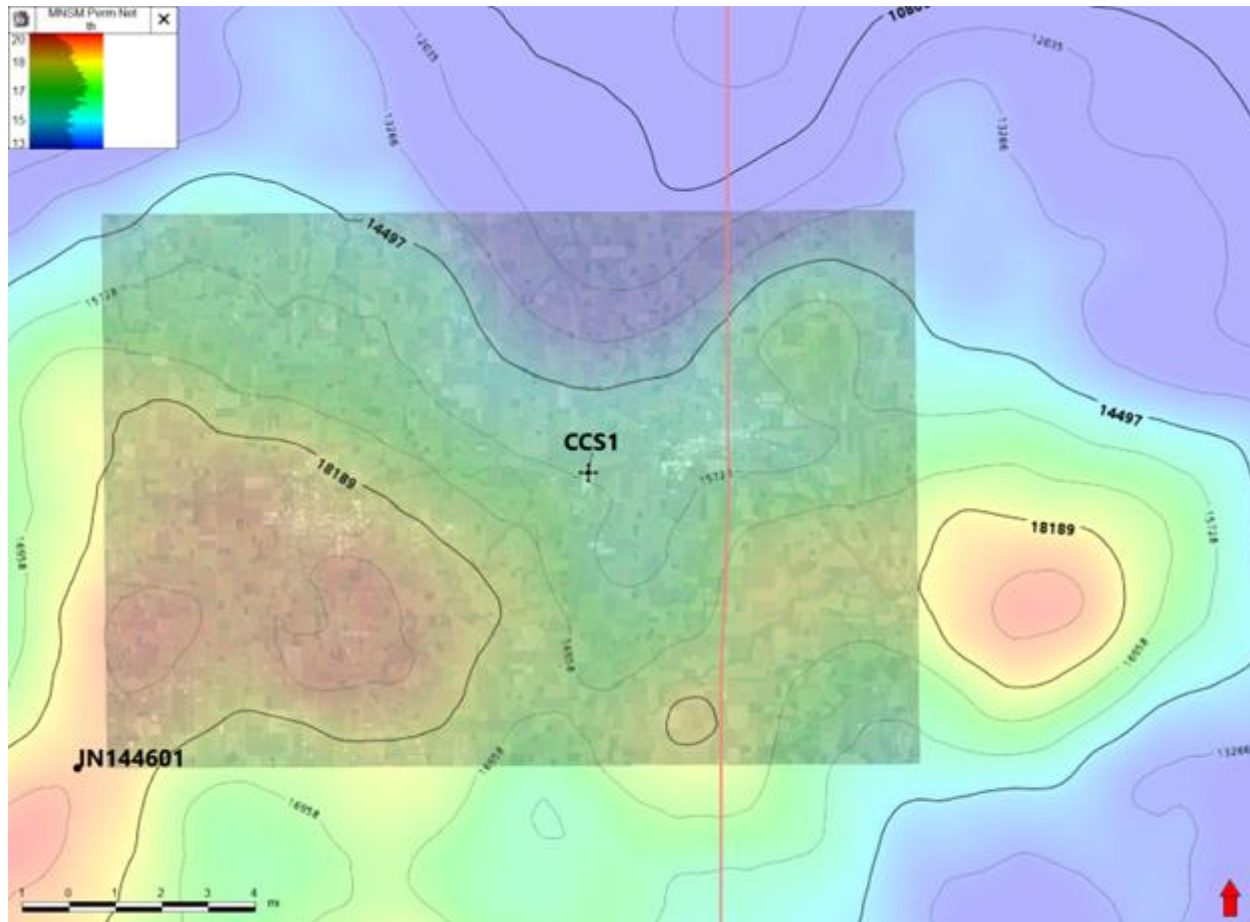


Figure 11: Permeability\*thickness (kh) Map of the Mt Simon Sandstone.

### 1.4.3 Geostatistical Summary

Geological property modelling is a complex process with many variables to optimize for each zone including variograms, co-kriging variables, data transformations, etc. A quality model should be statistically representative of the available well data and be geologically realistic. Statistical analyses were used throughout the static modeling in order to quickly identify potential errors and correct them.

Histogram displays from the model were generated for the AoR as part of the model quality control. Figure 12 shows the effective porosity and permeability histograms for the Eau Claire Shale, Eau Claire Silt, and Mt. Simon Sandstone for the AoR. Figure 13 displays the histograms of well log data, upscaled data (blocked wells) and the final property model to demonstrate how the facies properties were honored in the transition from the original well log data to the static model. Table 6 is a high-level summary of the geological characteristics of the static model.

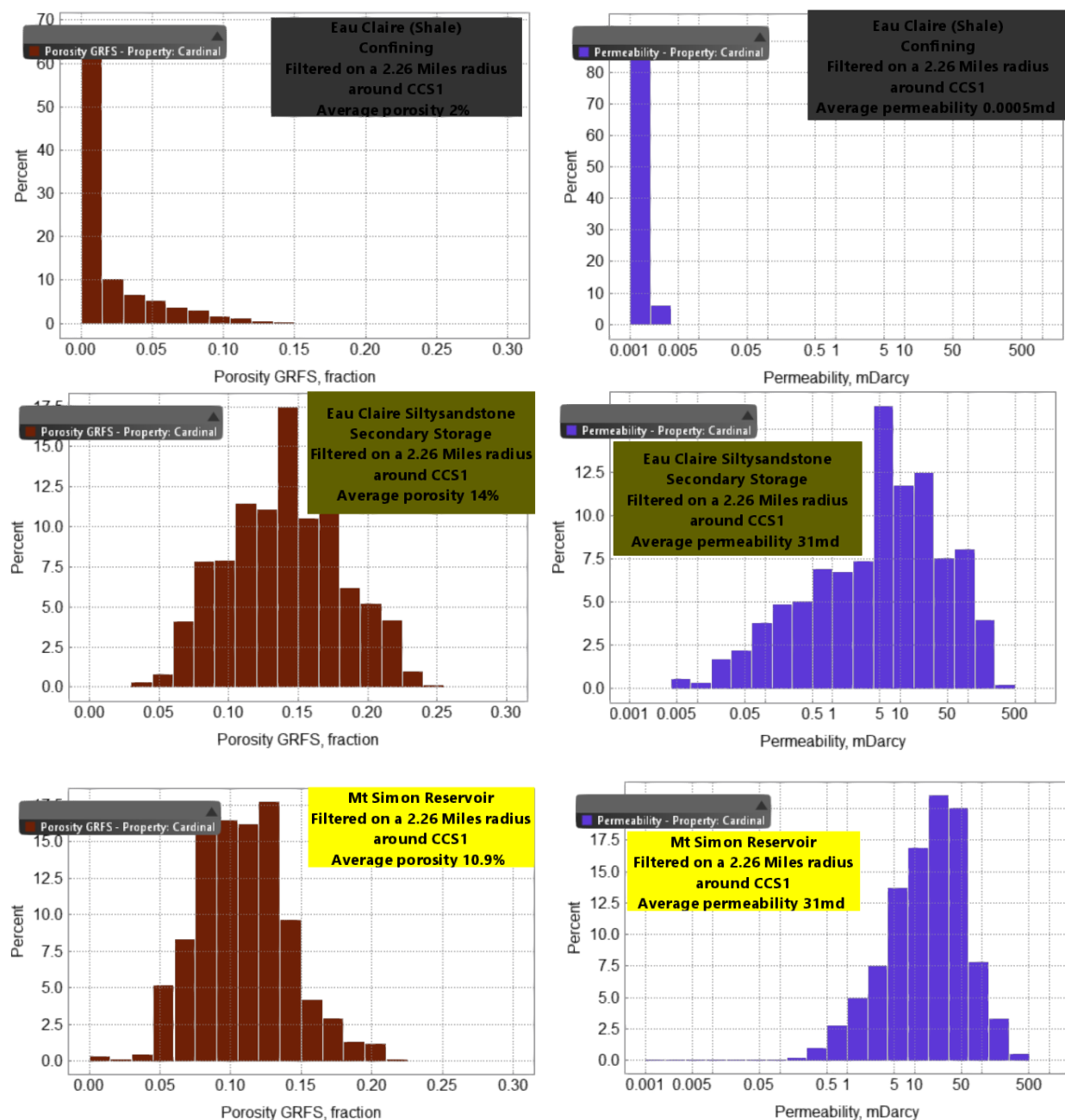


Figure 12: Effective porosity and permeability histograms for the 2.26-mile radius AoR around CCS1.

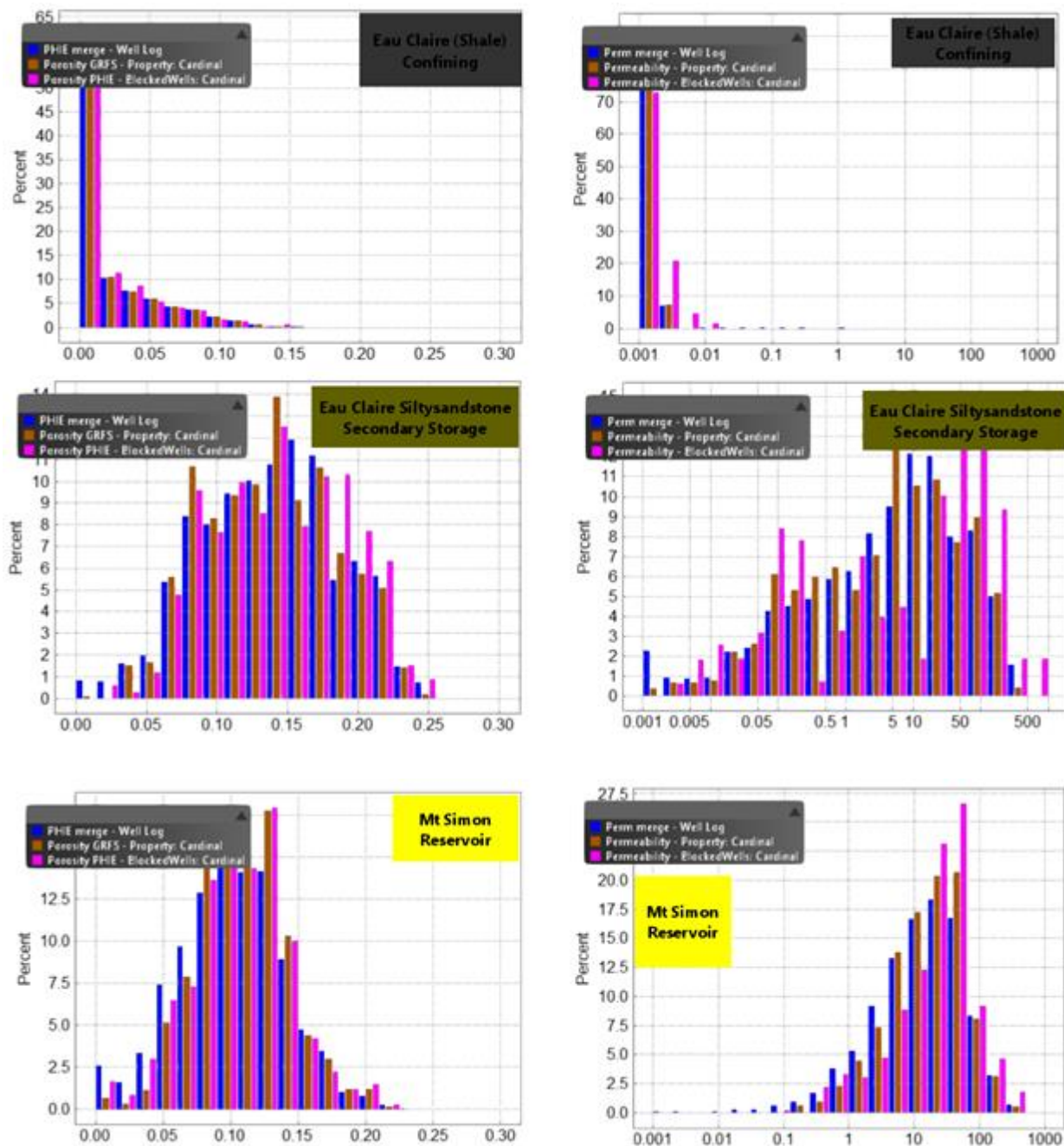


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<b>Formation</b>	<b>Facies</b>	<b>Average Porosity</b>	<b>Average Permeability</b>	<b>KH</b>	<b>Thickness (ft)</b>	<b>Elevation (fbsl)</b>	<b>Depth Below Ground TVD (ft)</b>
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Mt Simon Sandstone (injection zone)	Sandstone_1 Sandstone_2	10.9%	31 md	11,000-18,200	456-562	1,987-2,081	3,086-3,791
Precambrian	Precambrian	uncertain	uncertain	-	basement	2,492-2,609	3,592-3,715

At present, the static model is a reliable representation of the subsurface given the current input data; however, uncertainty will exist until site specific data is acquired through the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022). Site specific well log, core, well testing data, and 3D surface seismic data are collected during the pre-operational phase of the project. Once new data has been acquired and evaluated, the static model will be updated, and the accuracy will improve.

Wireline well logs from CCS1 and the deep observation well (OBS1) will be used to calibrate 3D surface seismic data and produce inversion products such as porosity and lithology cubes for the area of the surface seismic survey. The logs can also be used to generate a discrete facies log. The facies log can be combined with the lithology cube from the surface seismic data to provide more detail on the local depositional system. The updated static model will be used for a new update to the computational modeling as discussed in Section 4.5.

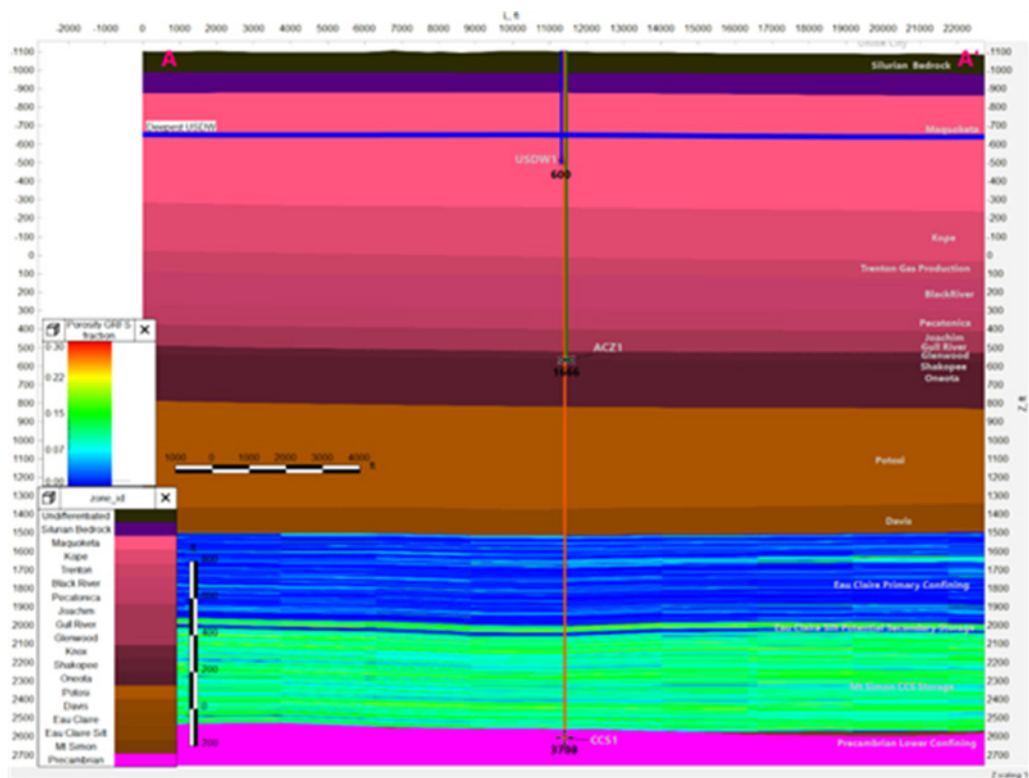
The conclusions of the geologic, petrophysical, and statistical analyses include:

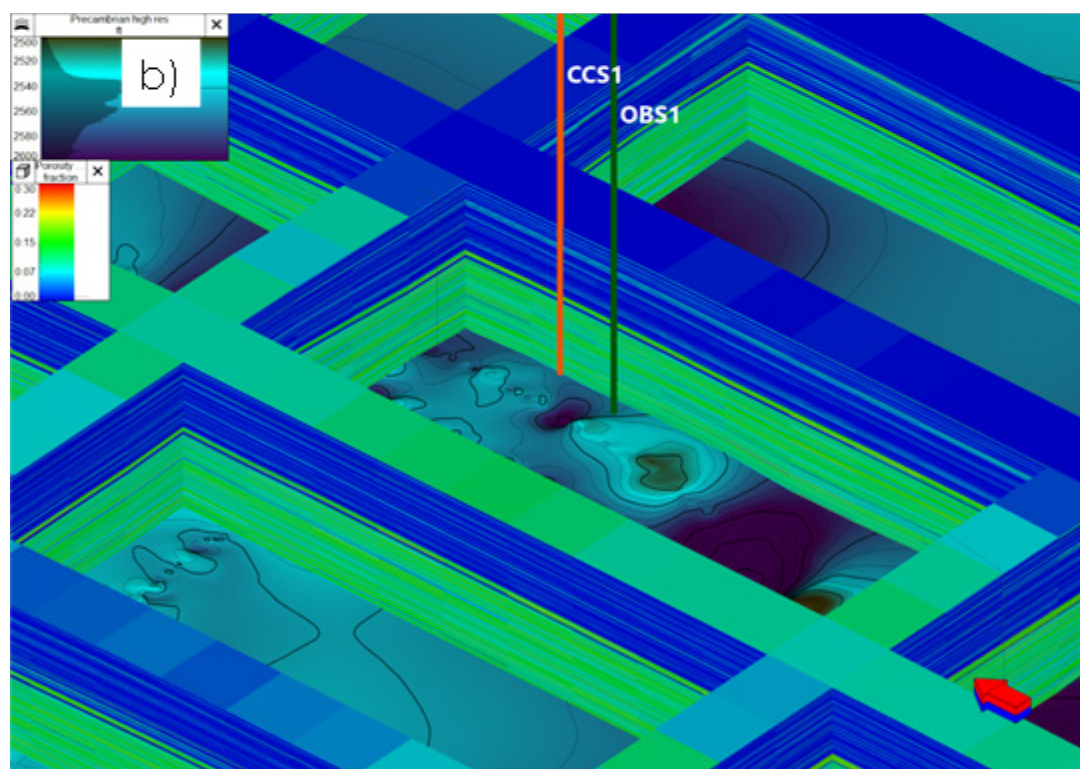
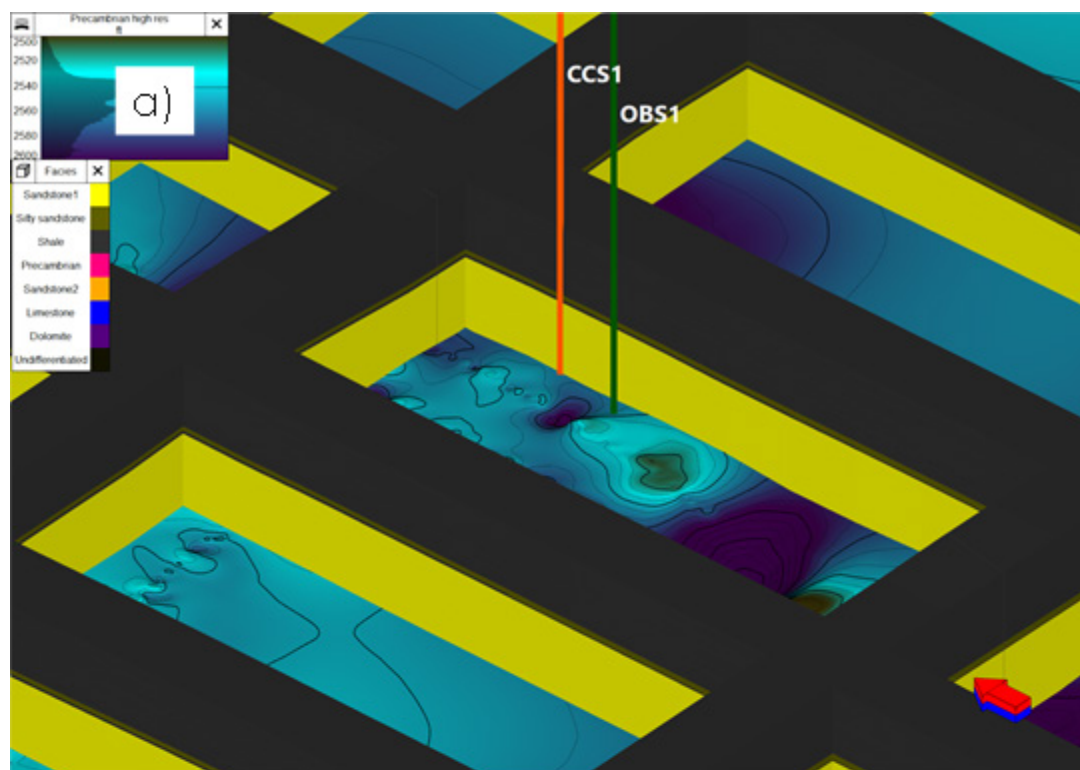
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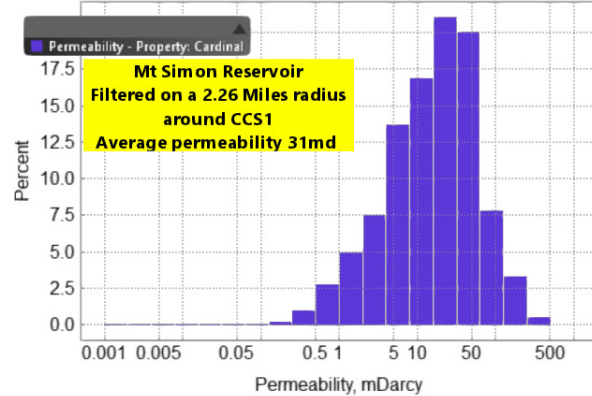
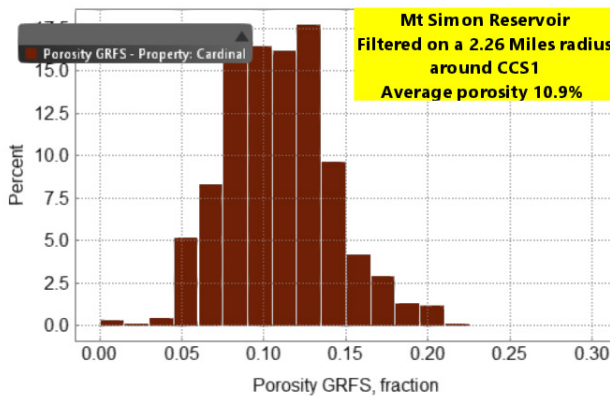
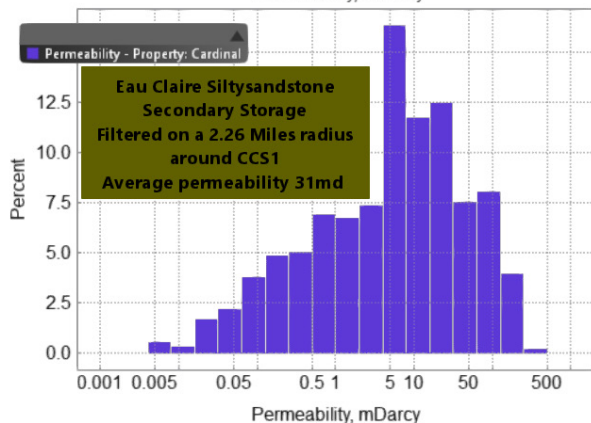
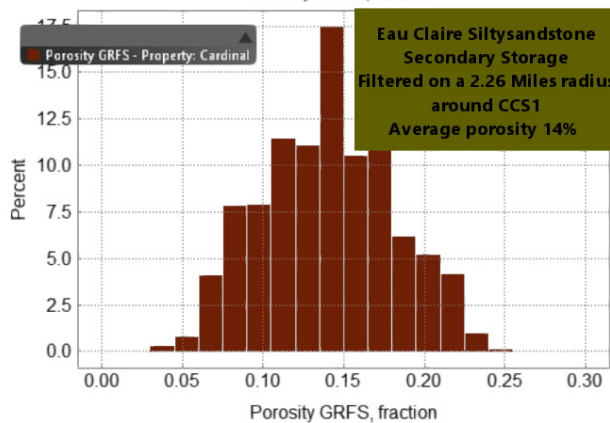
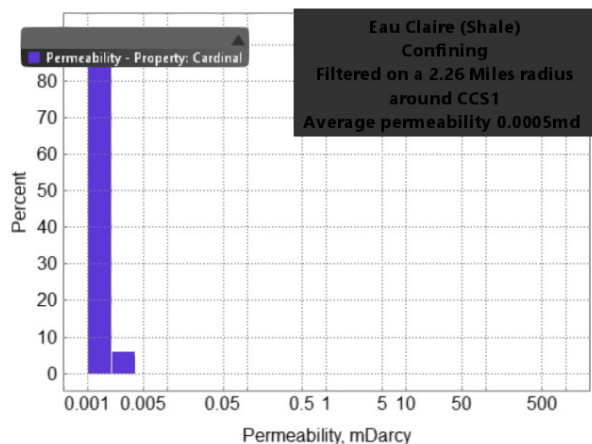
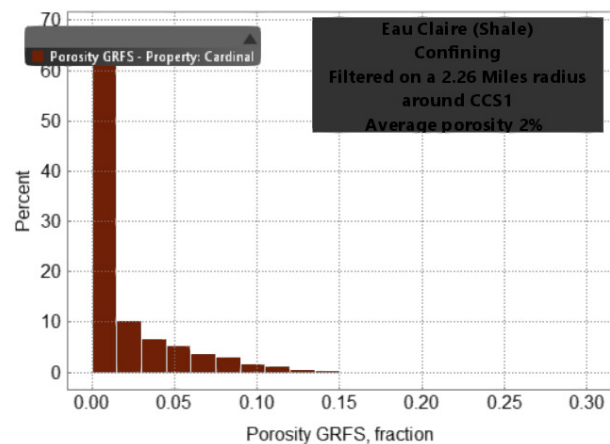
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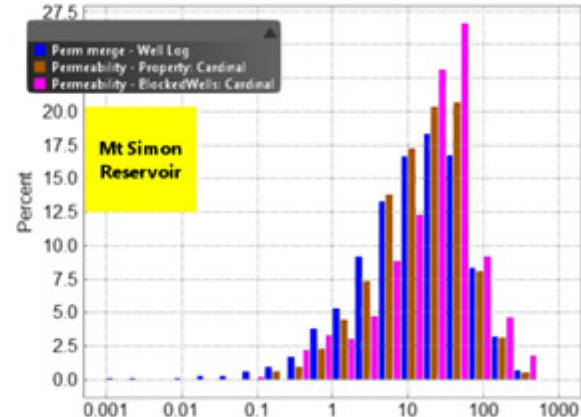
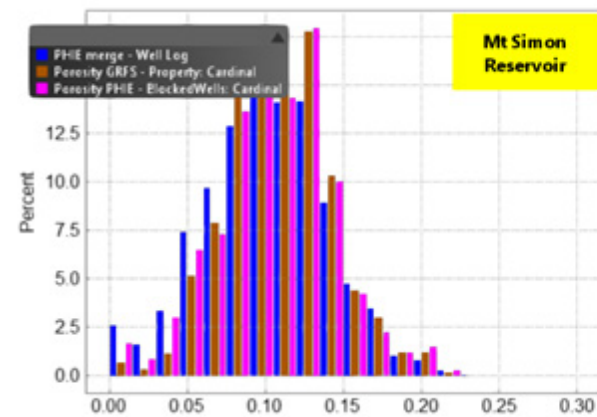
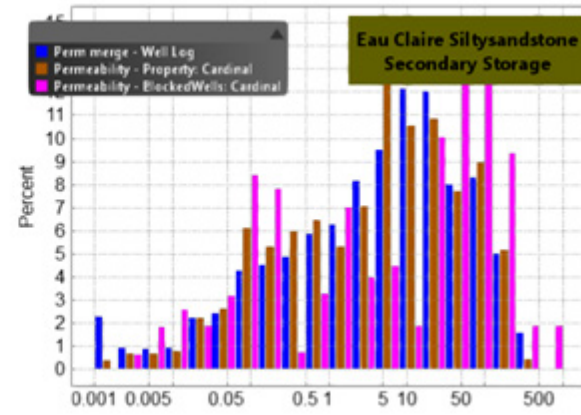
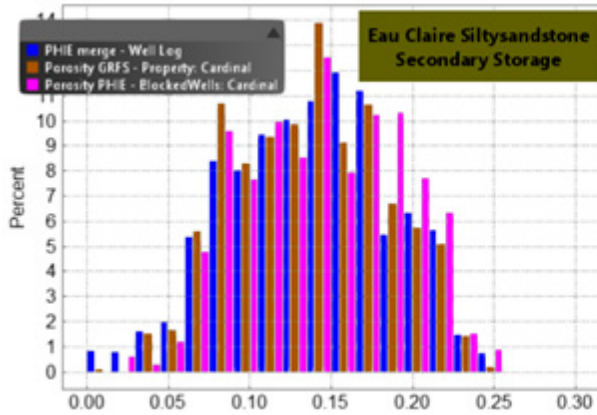
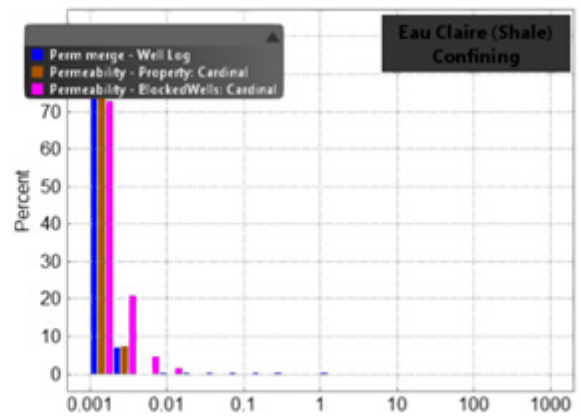
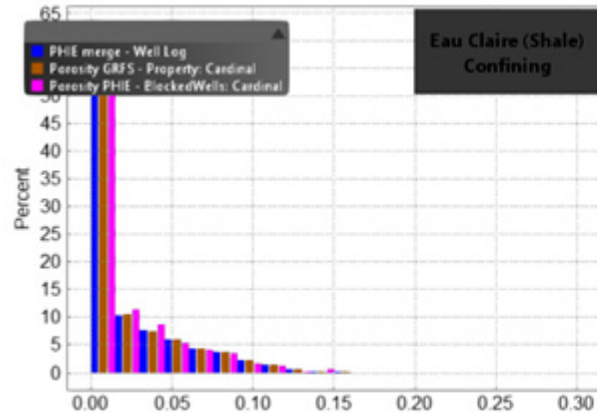
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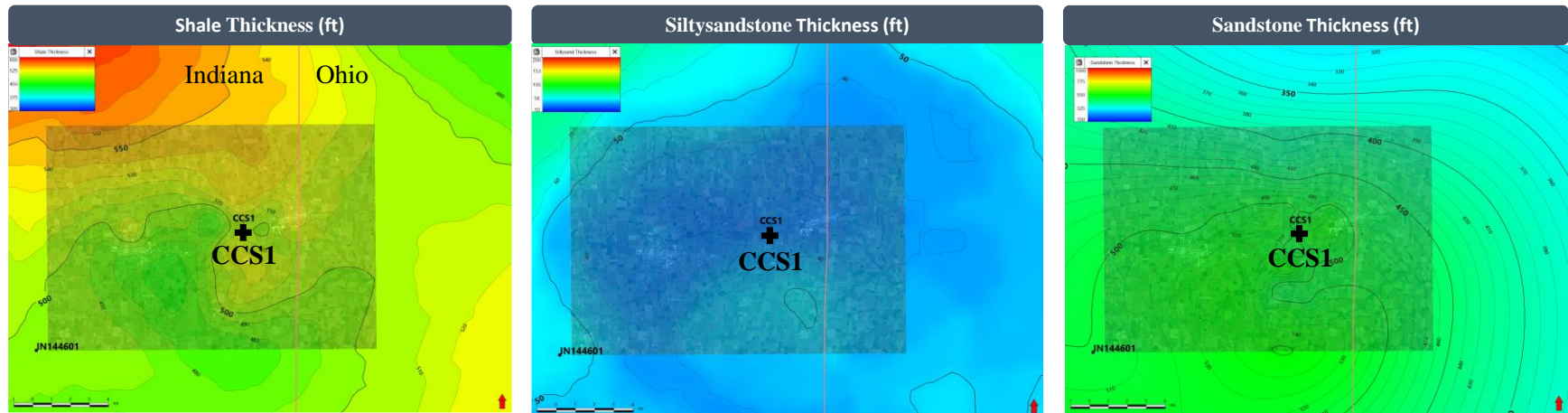


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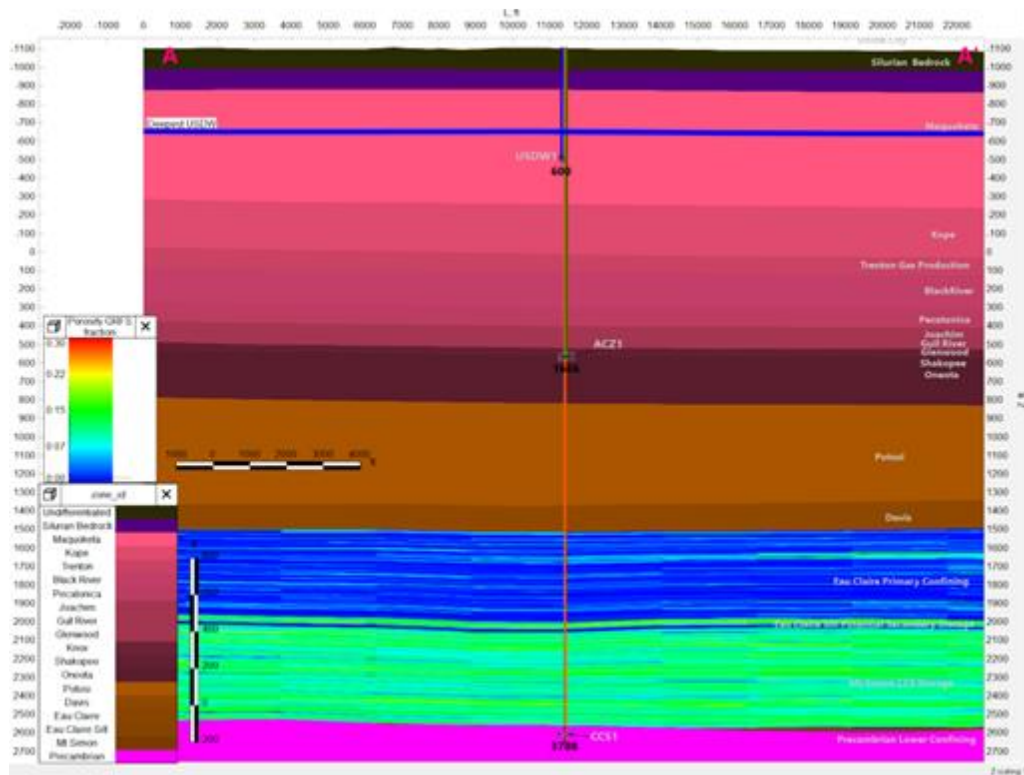


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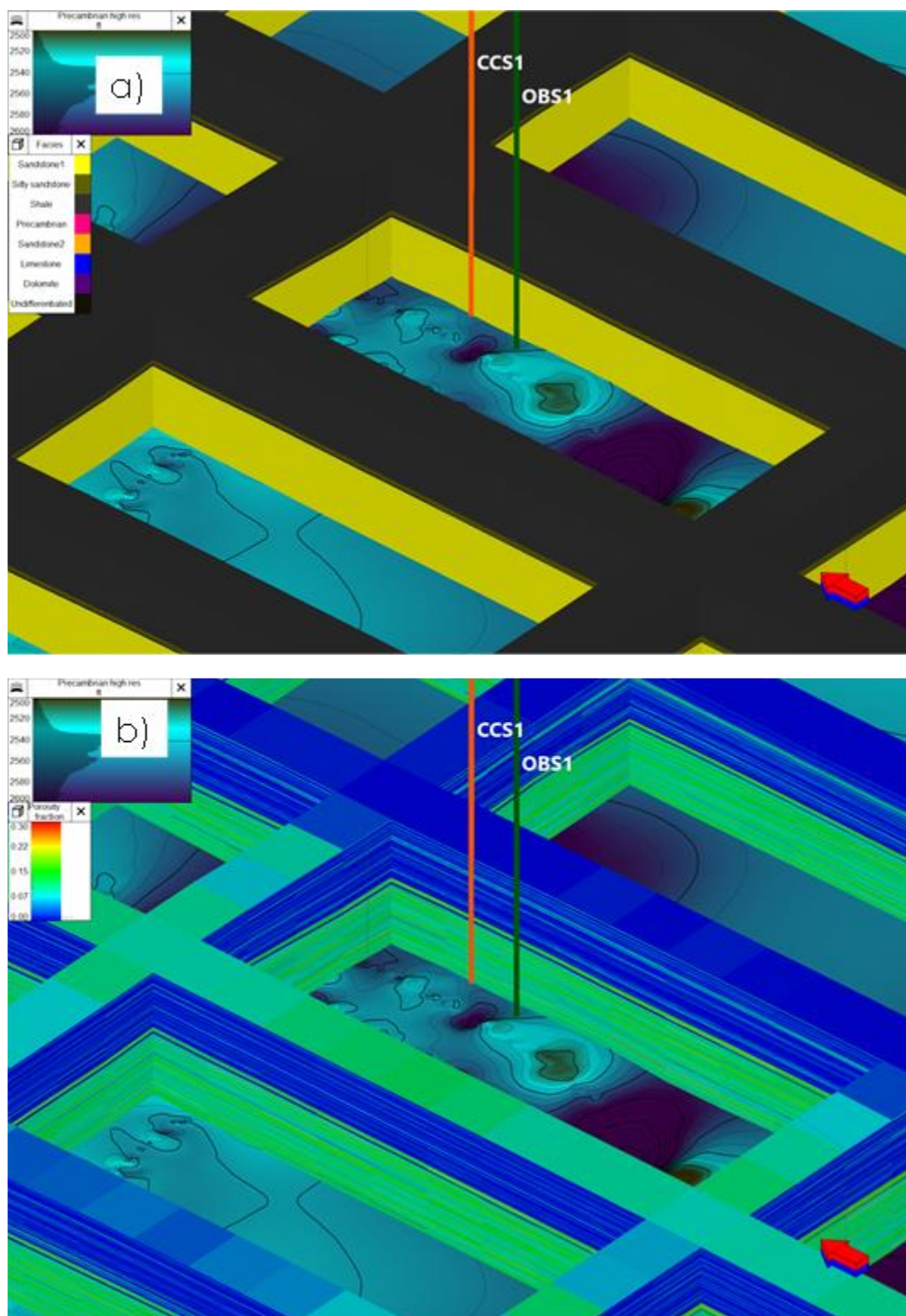


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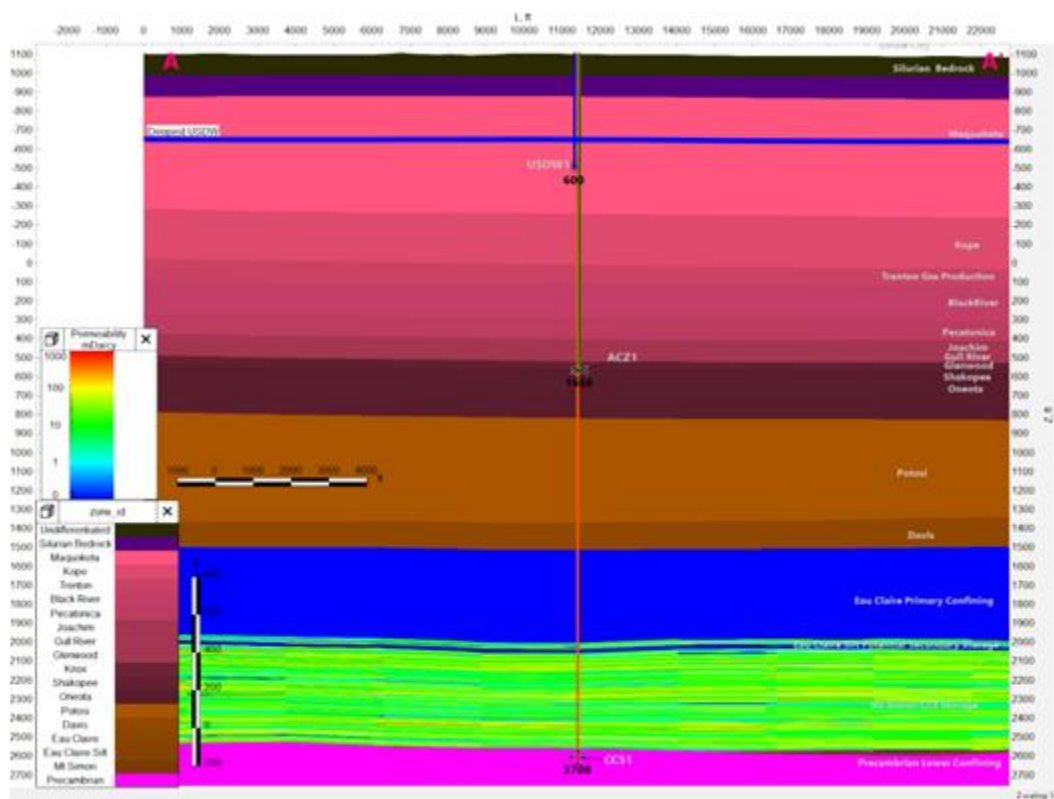


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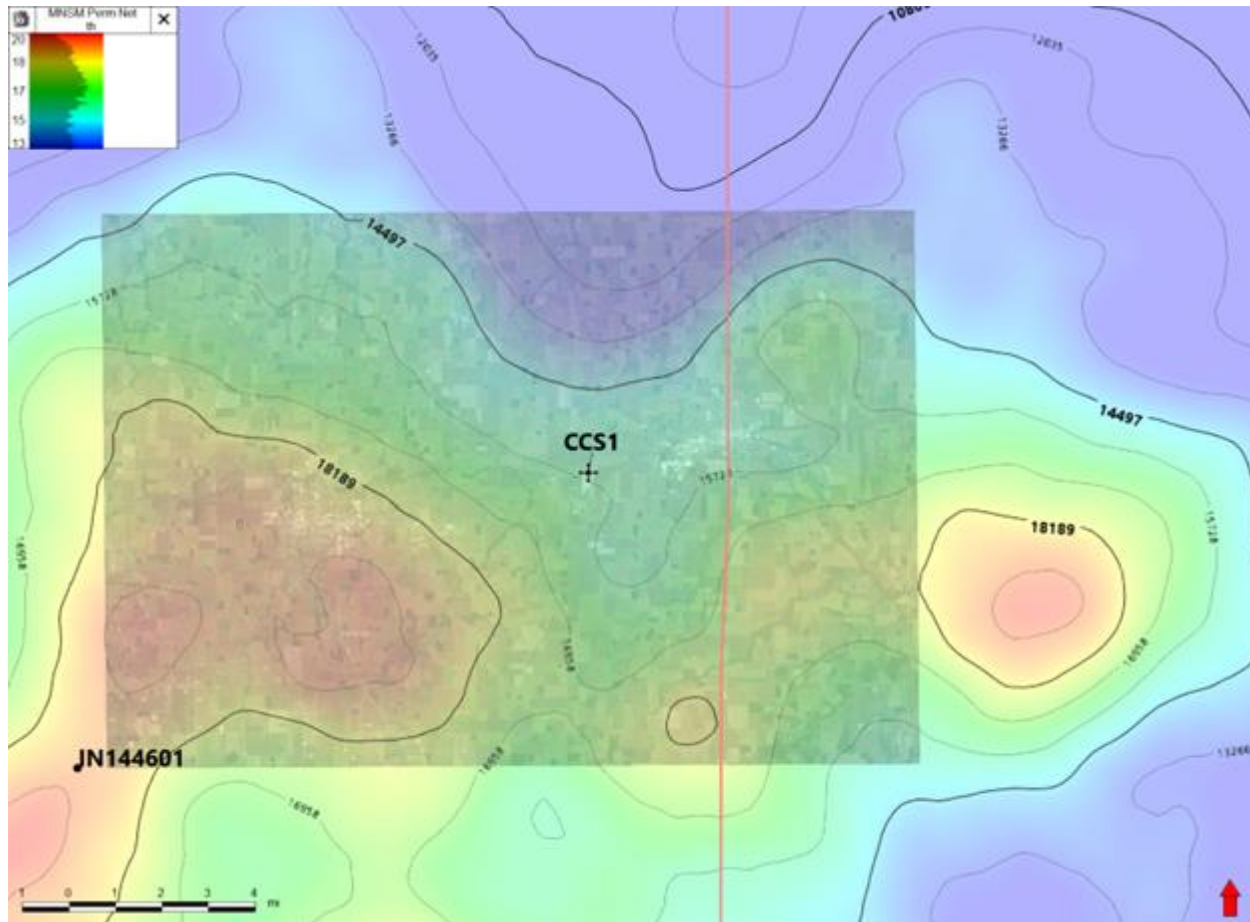


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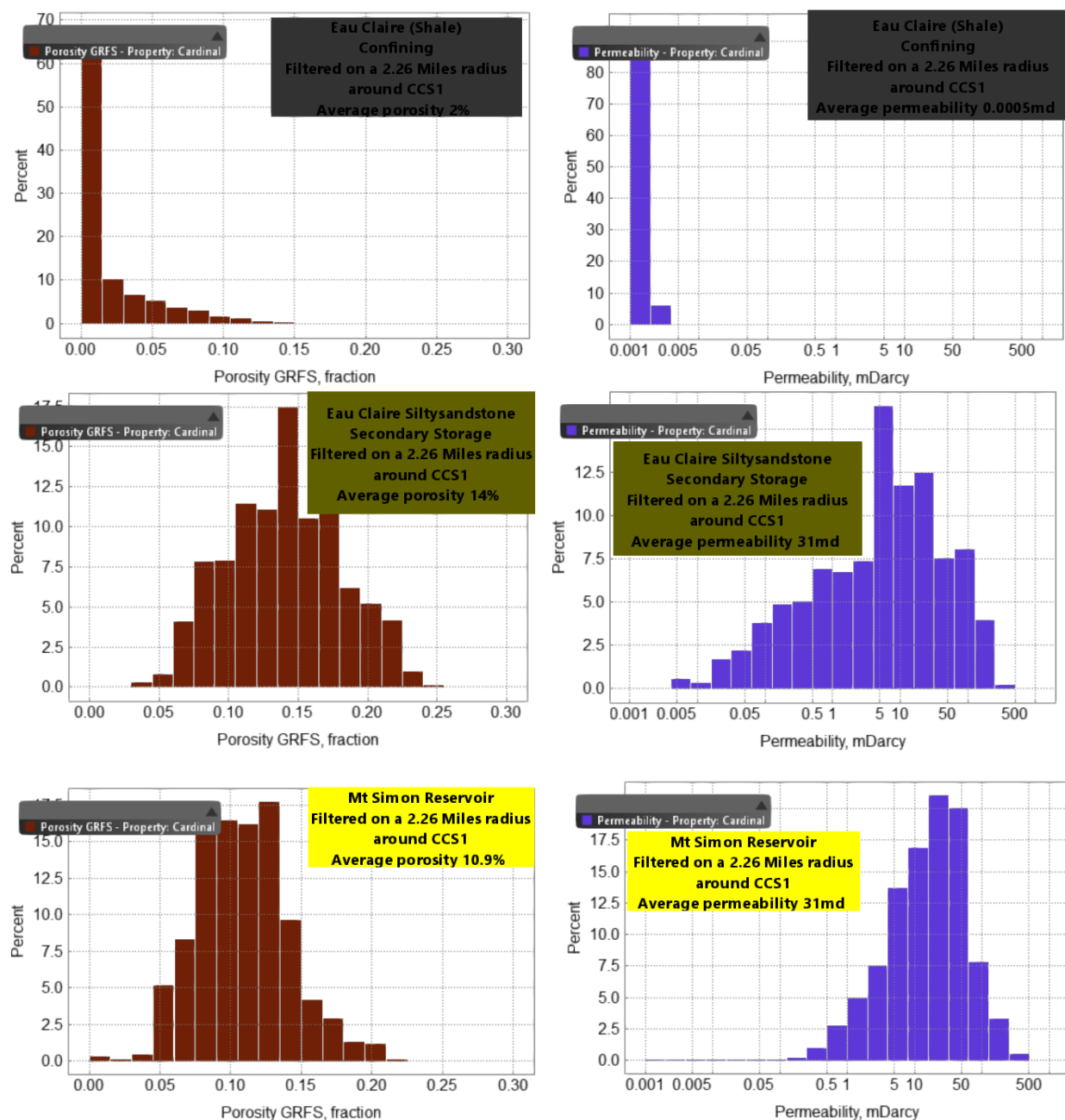


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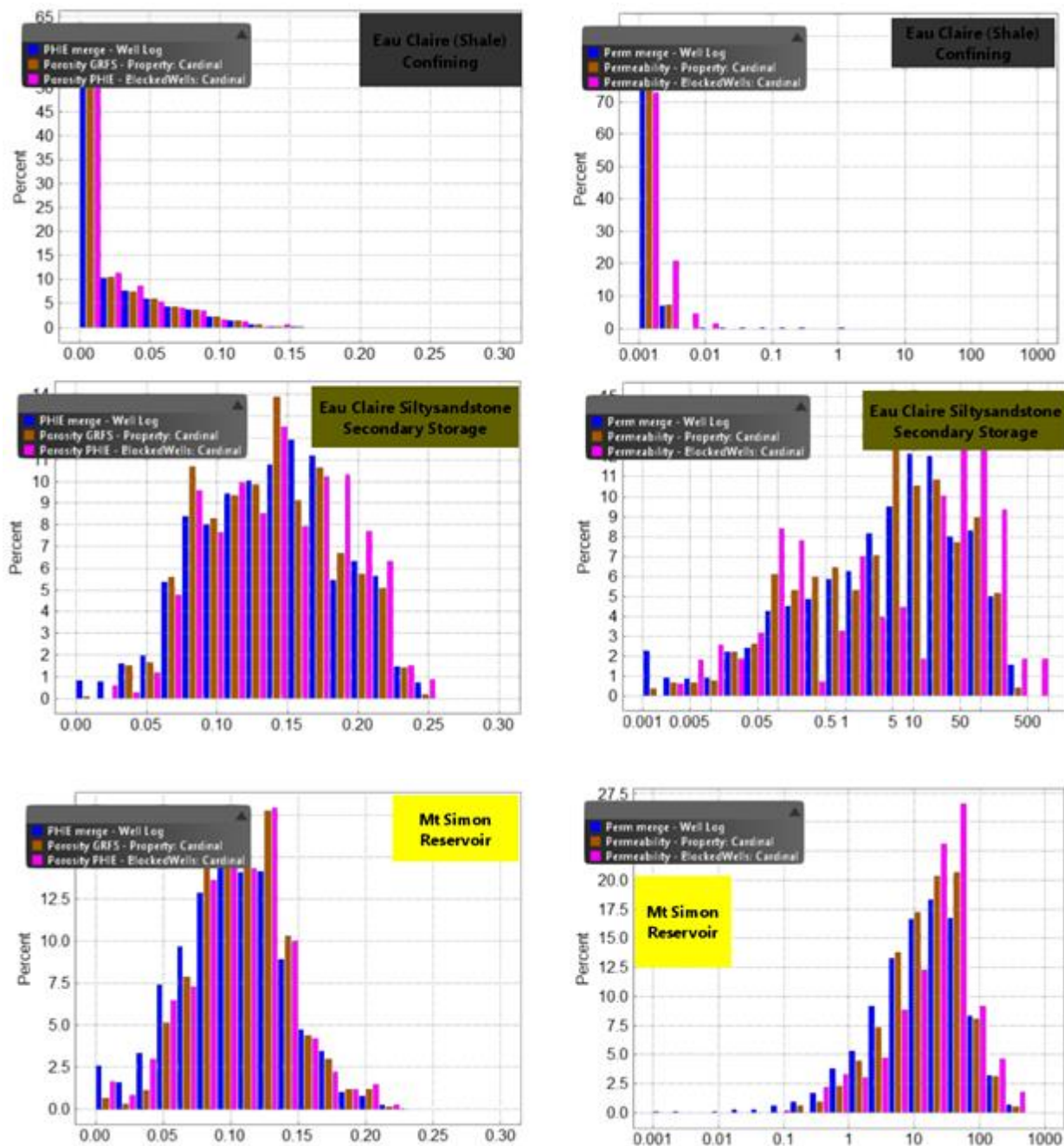


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- The Eau Claire Silt is a potential secondary sequestration zone.

In order to upscale well logs, an average algorithm is applied to the high-resolution well logs to produce one log value for each model cell that is penetrated by the well. Cell height plays a significant role in how porosity and permeability logs are upscaled and balances the capture of vertical heterogeneity while maintaining a manageable cell-count. Porosity values were upscaled into the grid using the arithmetic method (Figure 5).

The proportional vertical layering captured the variability observed in the porosity and permeability core data. The intent of this was to honor thin intervals in the injection zone that may represent significant permeability streaks, and thus play a significant role in dynamic reservoir behavior. The permeability upscaled cell was calculated from the equations in Figure 6. Figure 5 displays how the vertical variation of the wells with core was captured in the vertical property interpretation where there are data gaps.

**Figure 5: Confidential Business Information: Well log upscaling.**

**Figure 6: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey).**

### ***1.4.2 Facies and Petrophysical Modeling***

The upscaled core porosity from the nine wells provided high vertical resolution at each well for the static model; however, little was known about the porosity values between the wells. Therefore, variogram analysis was used to interpolate the data from the wells into the interwell space such that porosity represented the geological setting.

Facies were interpolated using the tNavigator Amazonas (Degterev, 2020) process that proved to be a reliable way to interpolate these facies data at these distances (Figure 7). The facies of the Eau Claire Formation consisted of primary shale with a thin layer of silty sandstone at the base which was modeled here to represent the Eau Claire Silt (potential secondary sequestration). The facies of the Mt Simon Sandstone were interpolated with two sandstone facies (Sandstone\_1 and Sandstone\_2). In the Precambrian, one facies was used. Figure 7 shows the facies thickness maps within the Mt Simon Sandstone and the Eau Claire Formation.

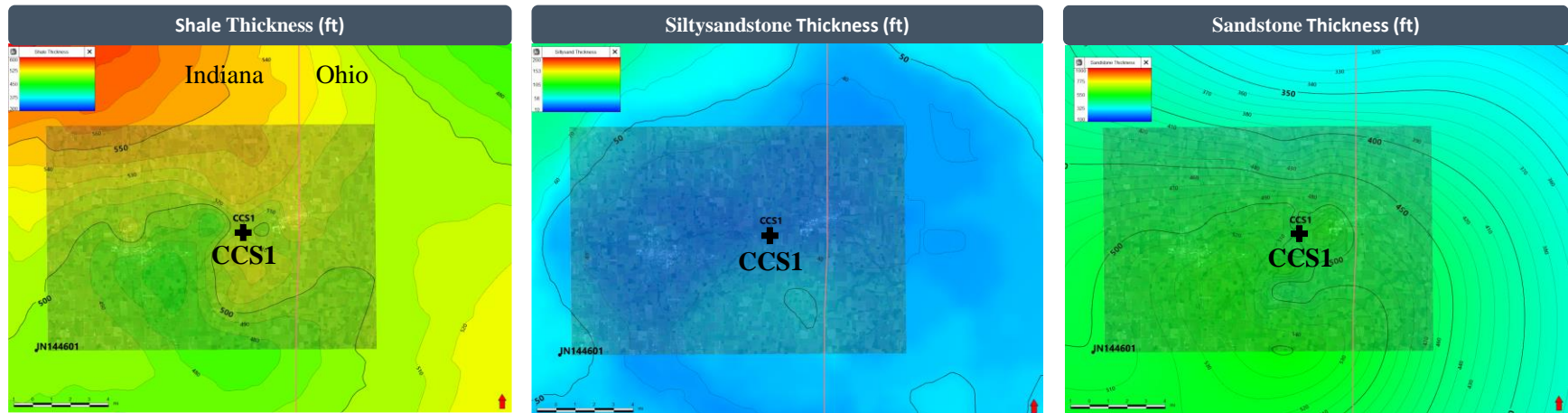


Figure 7: Facies thickness maps within the Mt. Simon Sandstone and Eau Claire Formation.

For each facies type, effective porosity was interpolated using Gaussian Random Function Simulation (GRFS) (Figure 8). Since the well data was sparse, a reliable horizontal variogram range and direction could not be extracted from variogram maps. To manage this issue, a horizontal variogram range of two miles was used in the horizontal direction. A vertical variogram range of approximately 10 feet was able to be extracted for each facies type. Figure 9 shows the relationship between the facies and effective porosity in the 3D model.

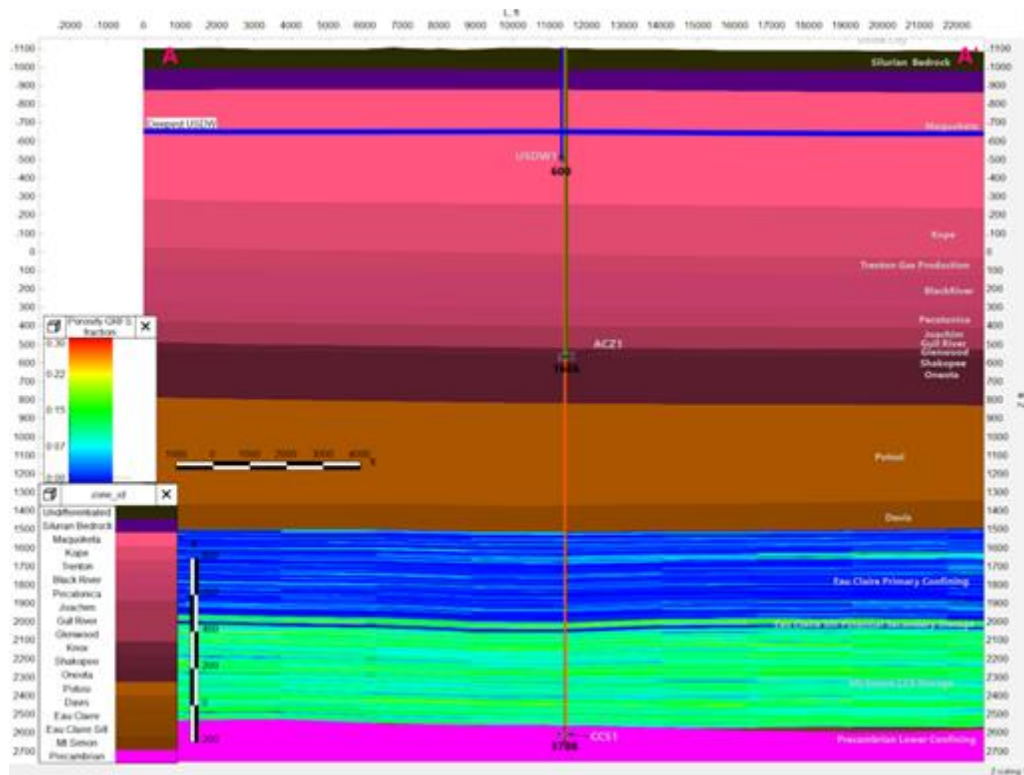


Figure 8: Cross Section A-A' formations and static model effective porosity.

The equations derived from Figure 6 were used to determine the effective porosity and permeability based on facies type (Figure 8 and Figure 10). The flow capacity of the injection zone can be characterized by the permeability-height product (kh) (Figure 11). The kh of the AoR compares favorably to the kh calculated from the fall-off test (FOT) reported in the INEOS (BP Lima) Nitrile disposal wells (INEOS USA LLC, 2015).

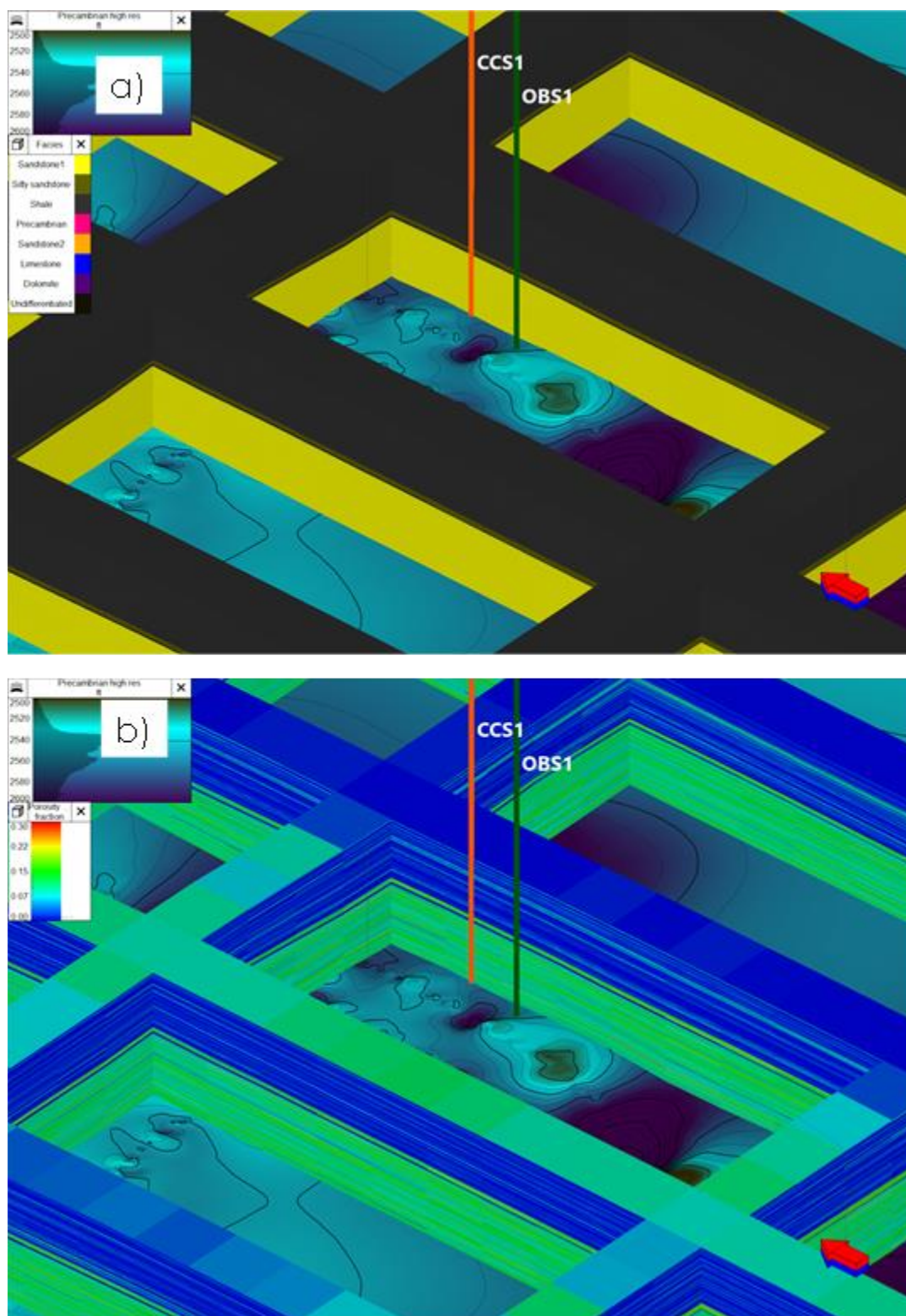


Figure 9: 3D view of static model showing a) facies, b) effective porosity.

Plan revision number: N/A  
 Plan revision date: July 4, 2022

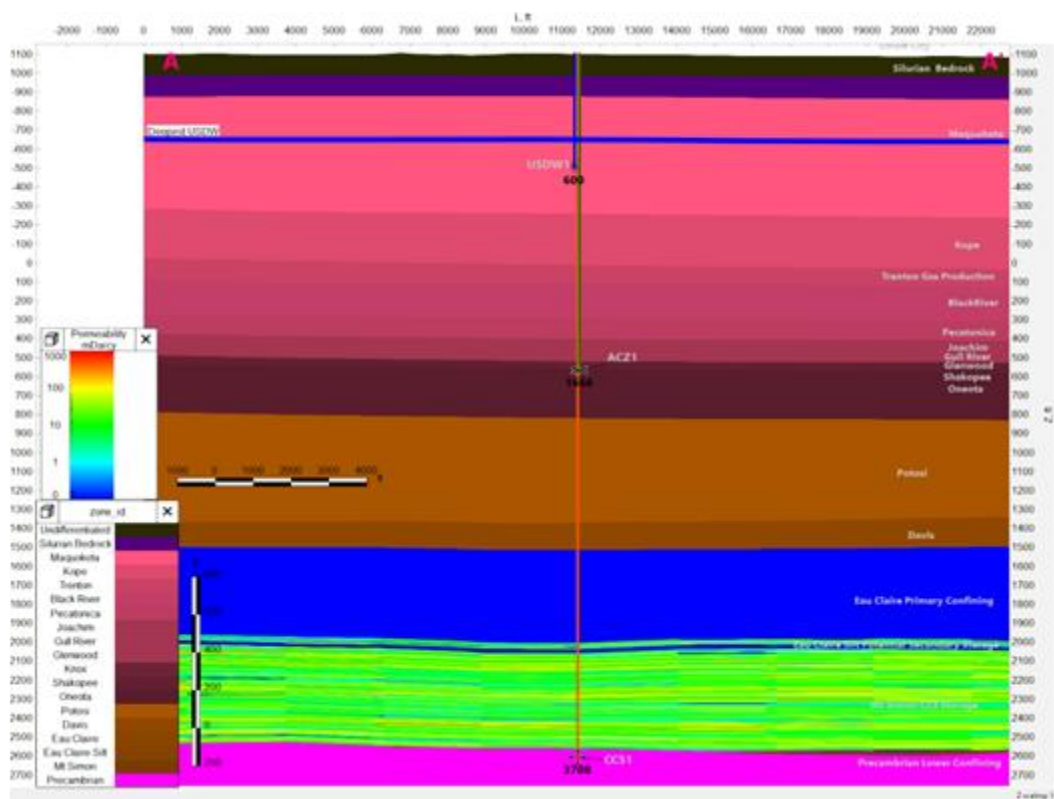


Figure 10: Cross Section A-A' formations and static model permeability.

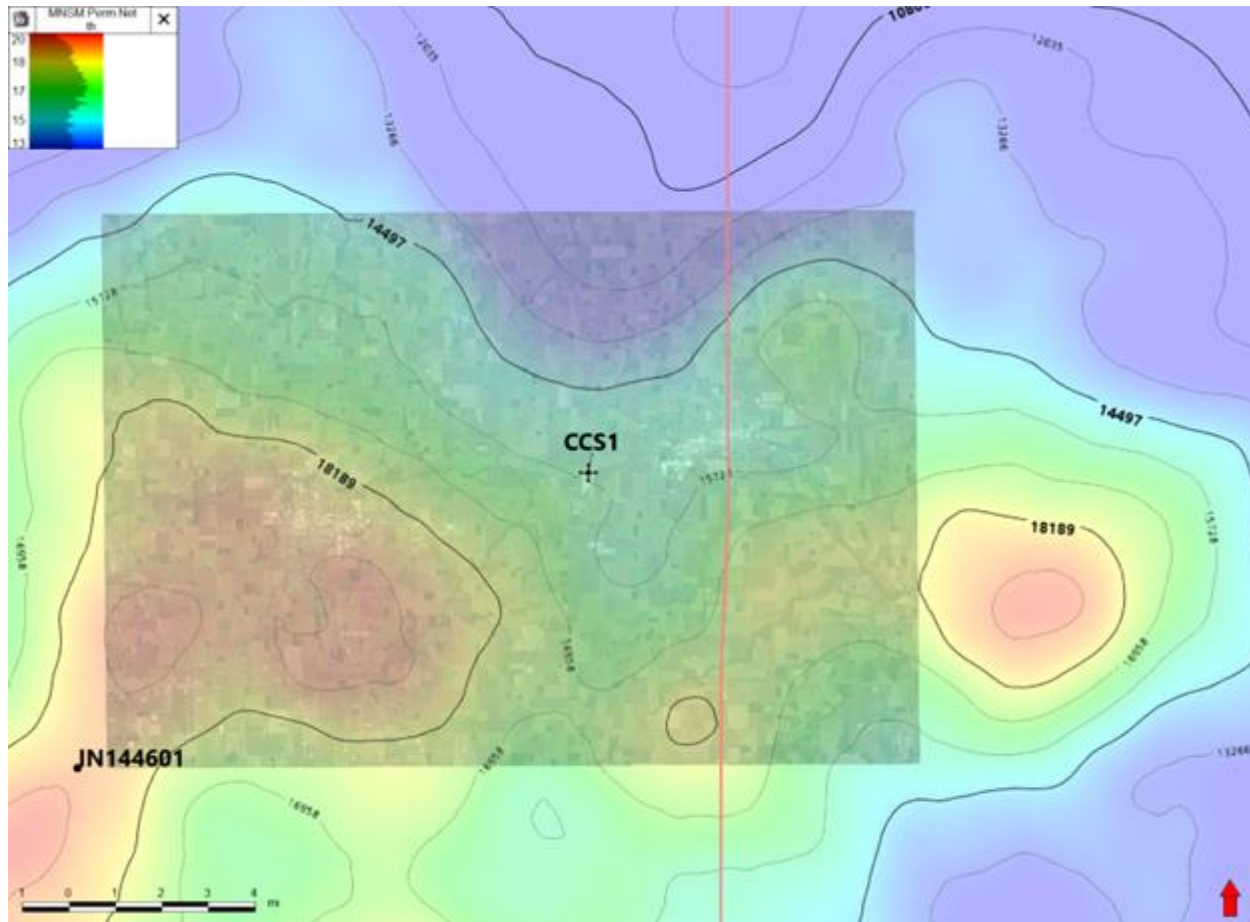


Figure 11: Permeability\*thickness (kh) Map of the Mt Simon Sandstone.

### 1.4.3 Geostatistical Summary

Geological property modelling is a complex process with many variables to optimize for each zone including variograms, co-kriging variables, data transformations, etc. A quality model should be statistically representative of the available well data and be geologically realistic. Statistical analyses were used throughout the static modeling in order to quickly identify potential errors and correct them.

Histogram displays from the model were generated for the AoR as part of the model quality control. Figure 12 shows the effective porosity and permeability histograms for the Eau Claire Shale, Eau Claire Silt, and Mt. Simon Sandstone for the AoR. Figure 13 displays the histograms of well log data, upscaled data (blocked wells) and the final property model to demonstrate how the facies properties were honored in the transition from the original well log data to the static model. Table 6 is a high-level summary of the geological characteristics of the static model.

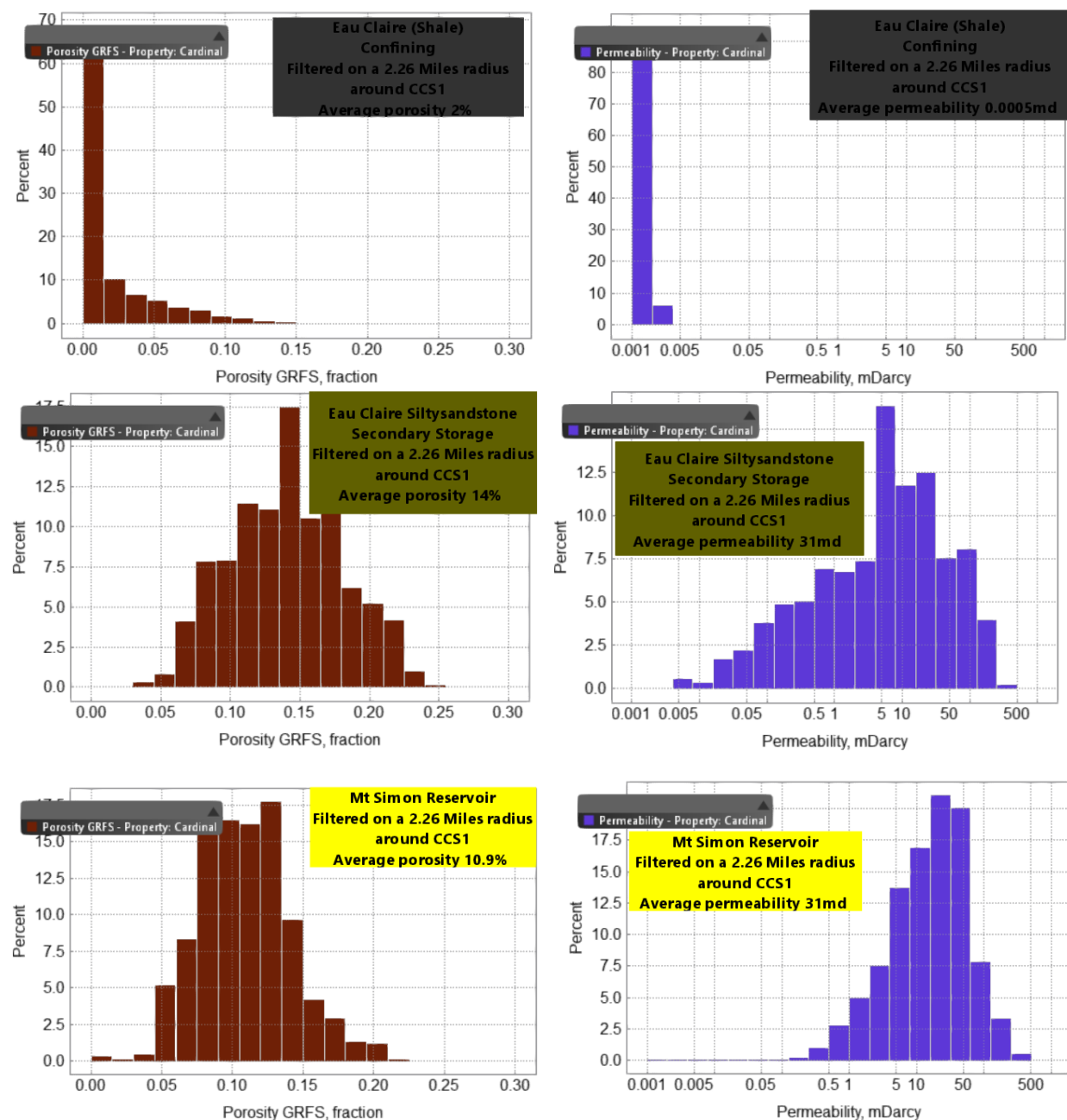


Figure 12: Effective porosity and permeability histograms for the 2.26-mile radius AoR around CCS1.

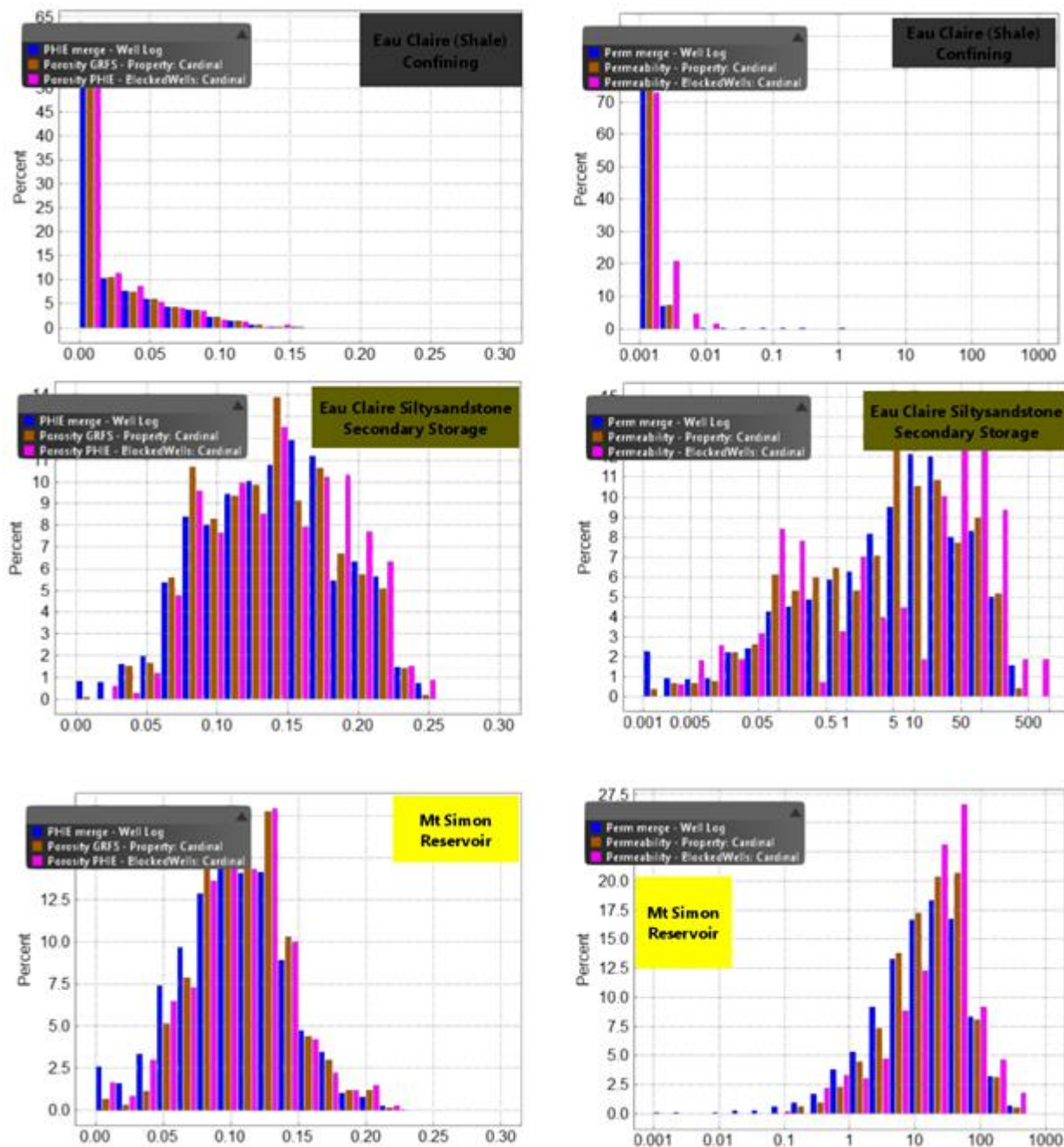


Figure 13: Effective porosity and permeability histograms of the well logs, upscaled logs (blocked wells) and the final interpolated property.

**Table 6: Summary of static model within the AoR.**

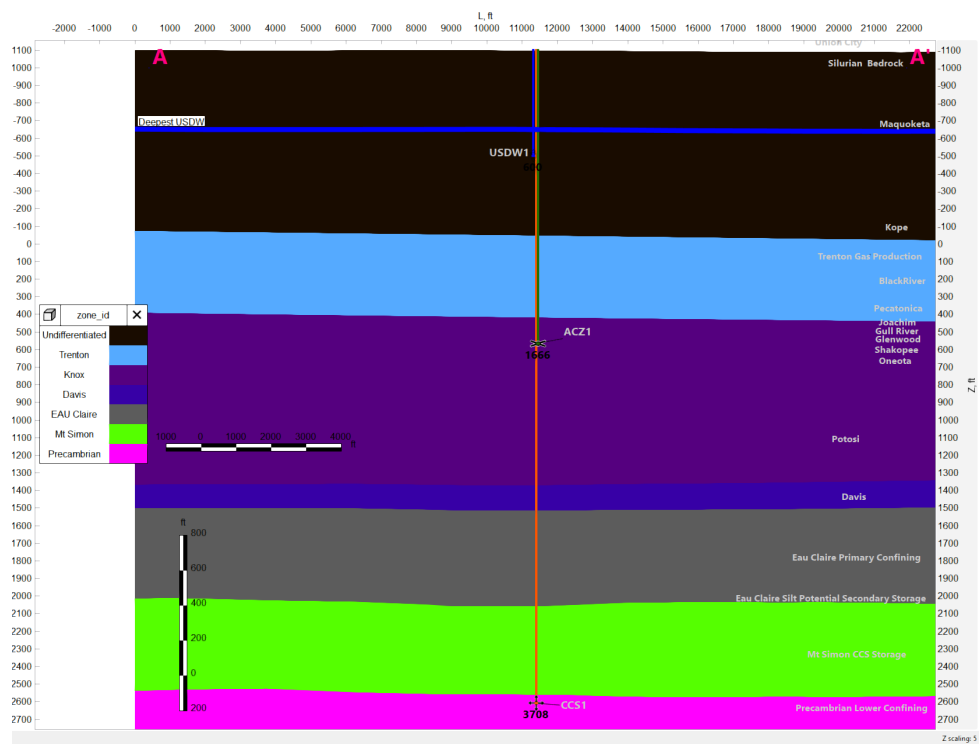
<b>Formation</b>	<b>Facies</b>	<b>Average Porosity</b>	<b>Average Permeability</b>	<b>KH</b>	<b>Thickness (ft)</b>	<b>Elevation (fbsl)</b>	<b>Depth Below Ground TVD (ft)</b>
Eau Claire Shale (confining zone)	Shale	2%	0.0005 md	<100	493-553	1,490-1,530	2,578-2,622
Eau Claire Silt (secondary sequestration)	Silty Sandstone	14%	22.6 md	840	~60	1,927-2,021	3,026-3,731
Mt Simon Sandstone (injection zone)	Sandstone_1 Sandstone_2	10.9%	31 md	11,000-18,200	456-562	1,987-2,081	3,086-3,791
Precambrian	Precambrian	uncertain	uncertain	-	basement	2,492-2,609	3,592-3,715

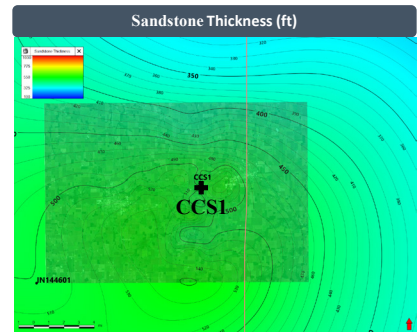
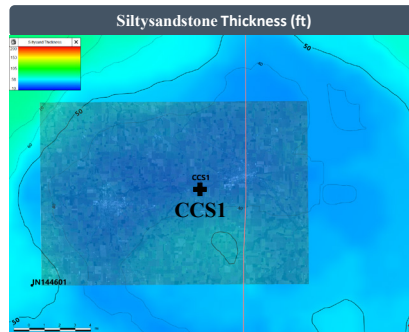
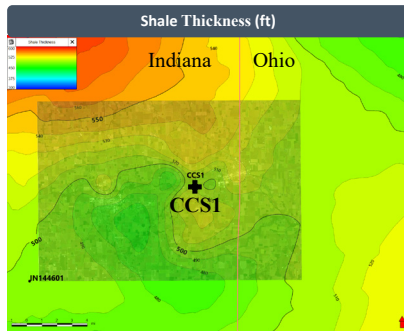
At present, the static model is a reliable representation of the subsurface given the current input data; however, uncertainty will exist until site specific data is acquired through the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022). Site specific well log, core, well testing data, and 3D surface seismic data are collected during the pre-operational phase of the project. Once new data has been acquired and evaluated, the static model will be updated, and the accuracy will improve.

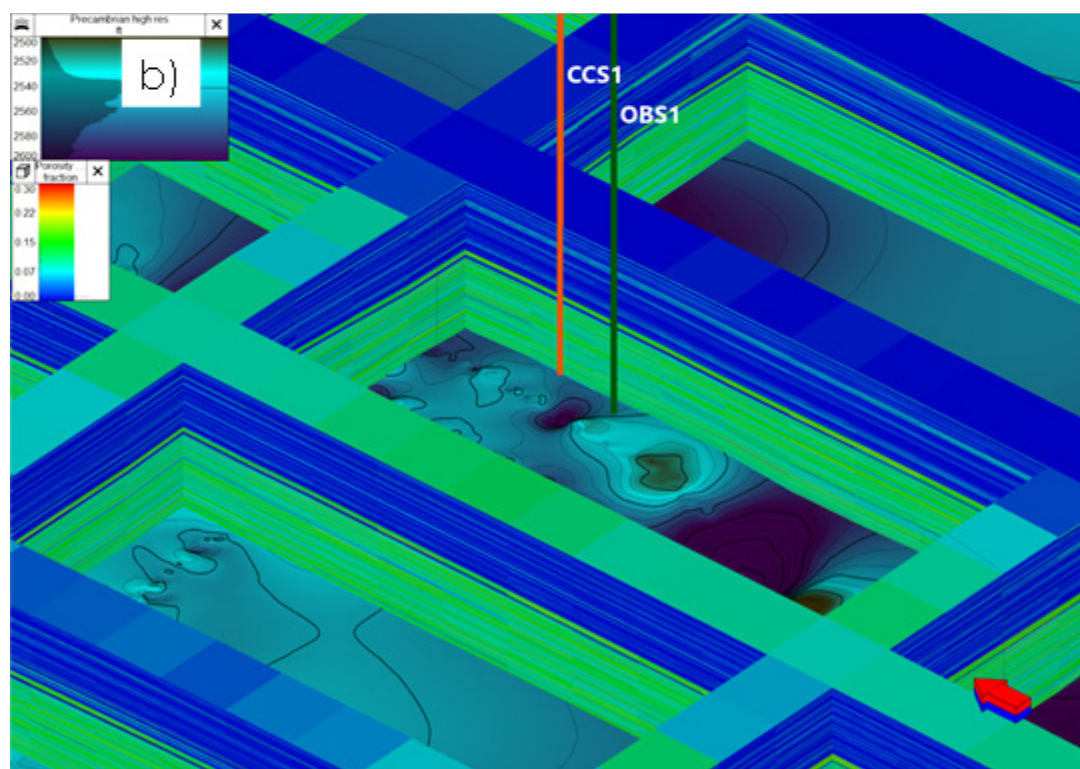
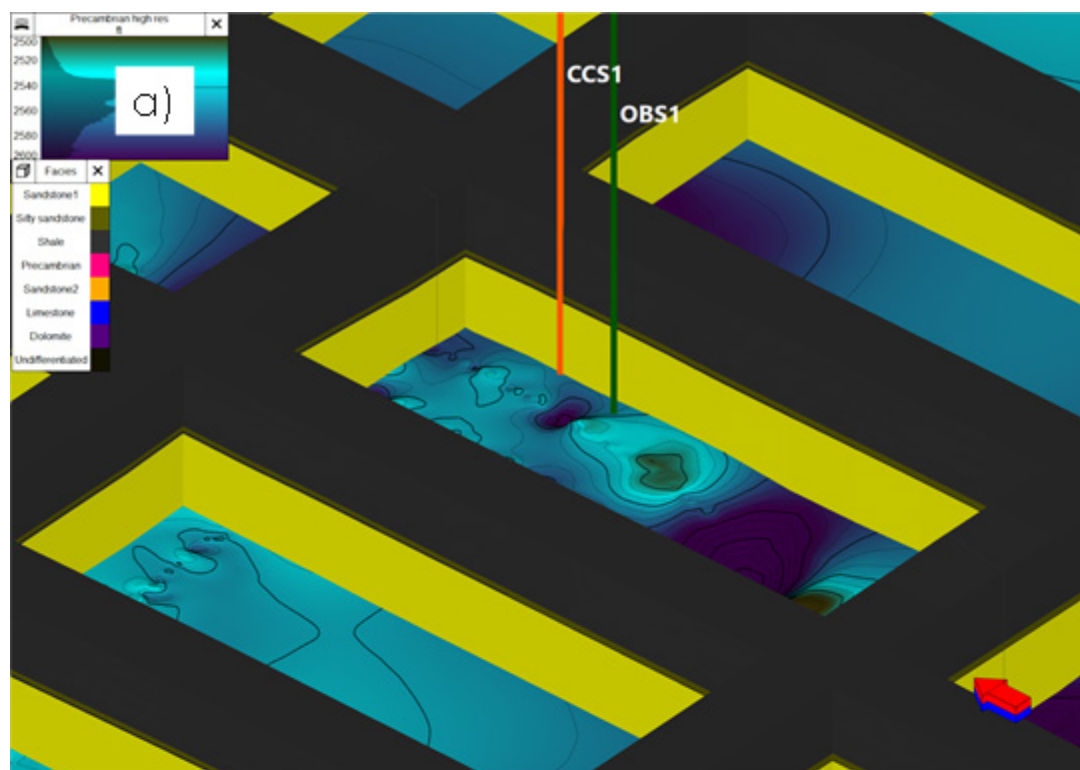
Wireline well logs from CCS1 and the deep observation well (OBS1) will be used to calibrate 3D surface seismic data and produce inversion products such as porosity and lithology cubes for the area of the surface seismic survey. The logs can also be used to generate a discrete facies log. The facies log can be combined with the lithology cube from the surface seismic data to provide more detail on the local depositional system. The updated static model will be used for a new update to the computational modeling as discussed in Section 4.5.

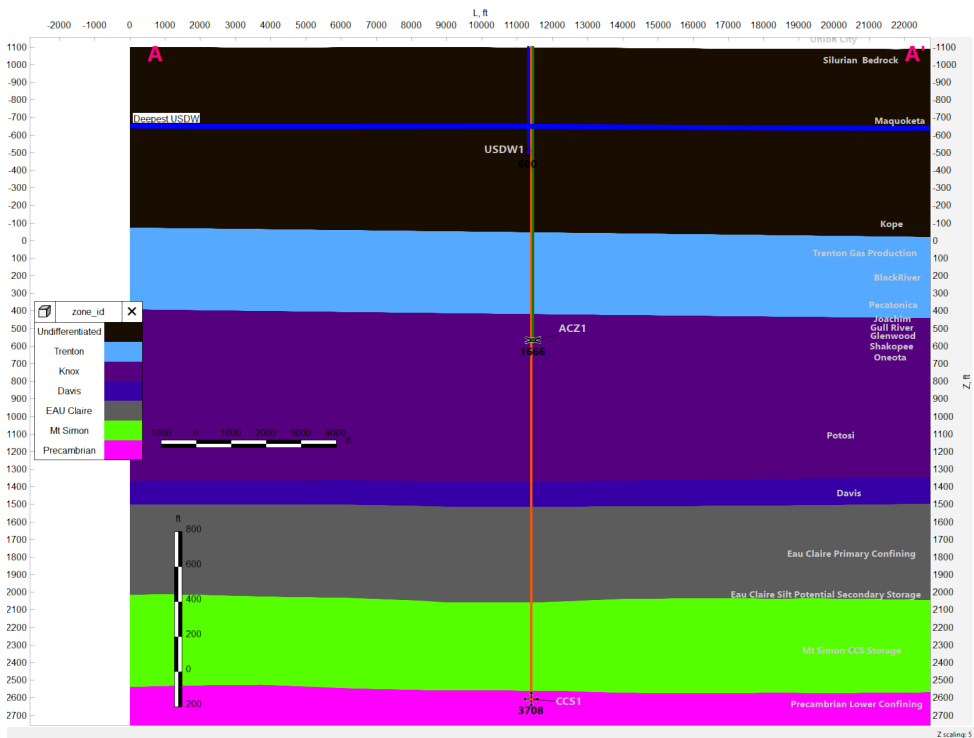
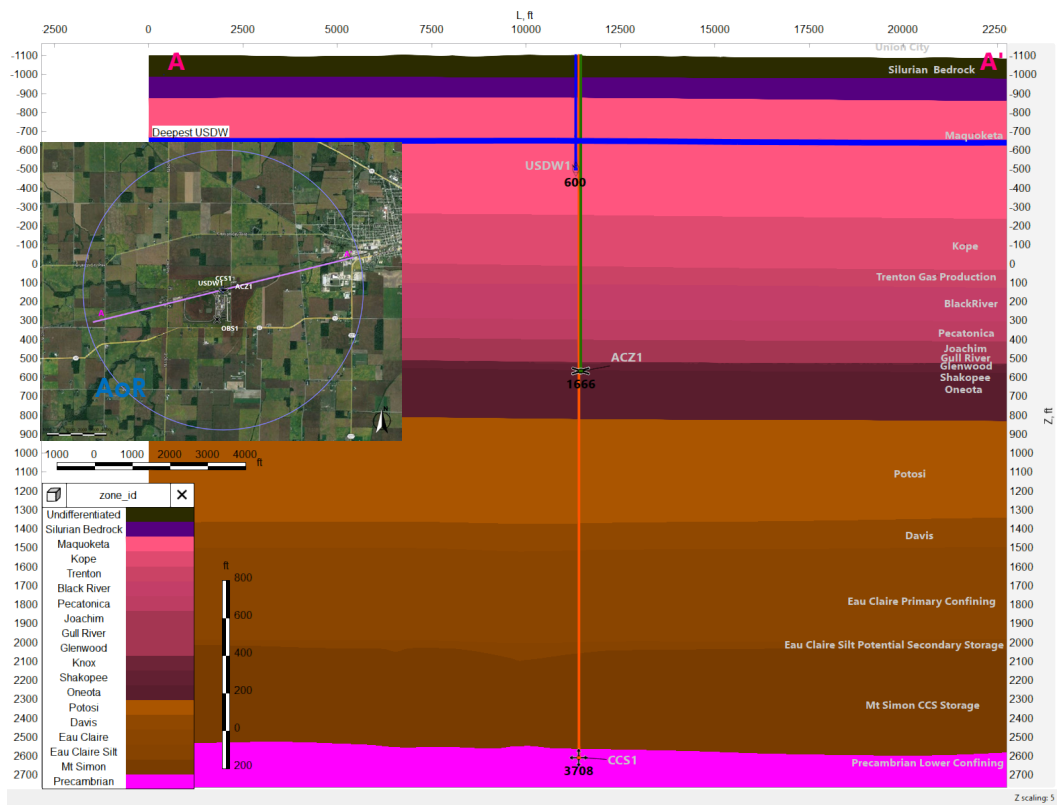
The conclusions of the geologic, petrophysical, and statistical analyses include:

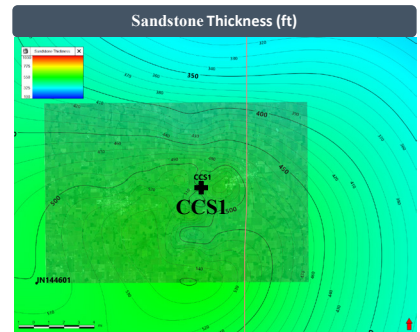
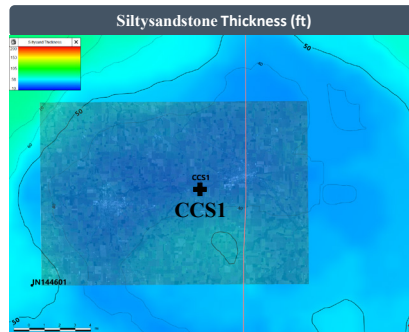
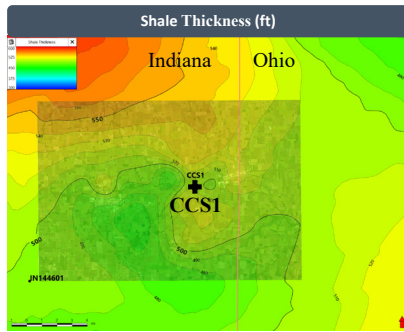
- The Eau Claire Formation is a thick low permeability confining zone.
- The Mt Simon Sandstone's thickness and petrophysical properties make it a reliable injection zone.
- The Eau Claire Silt is a potential secondary sequestration zone.

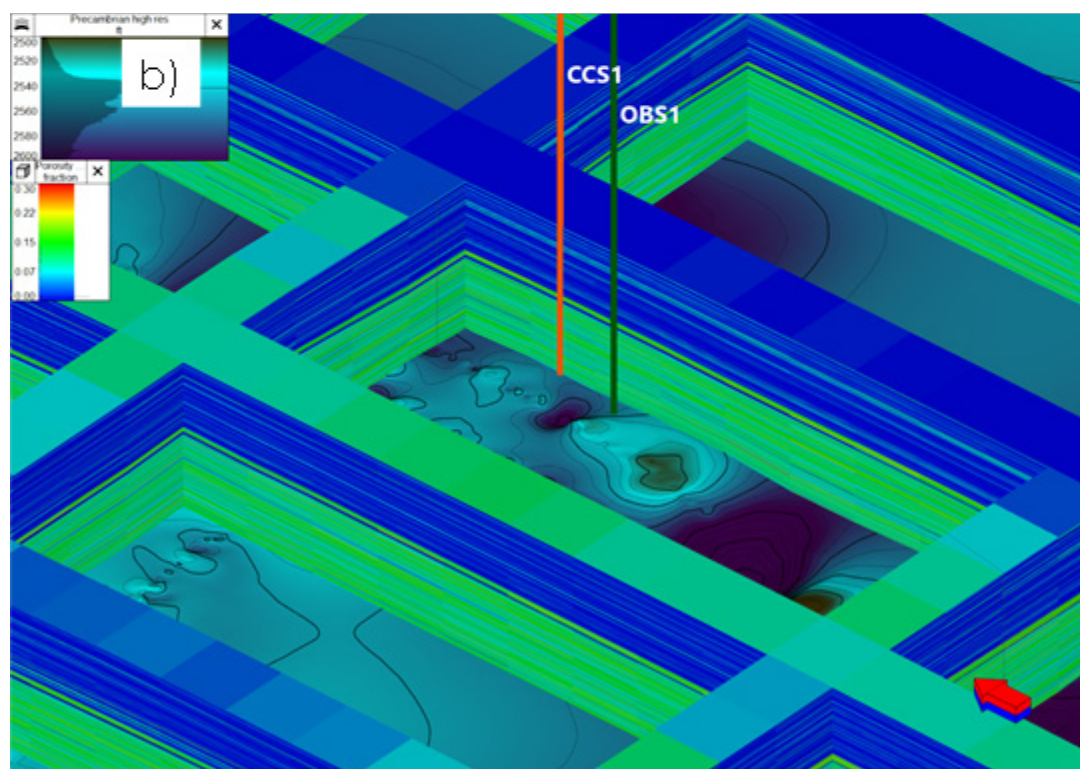
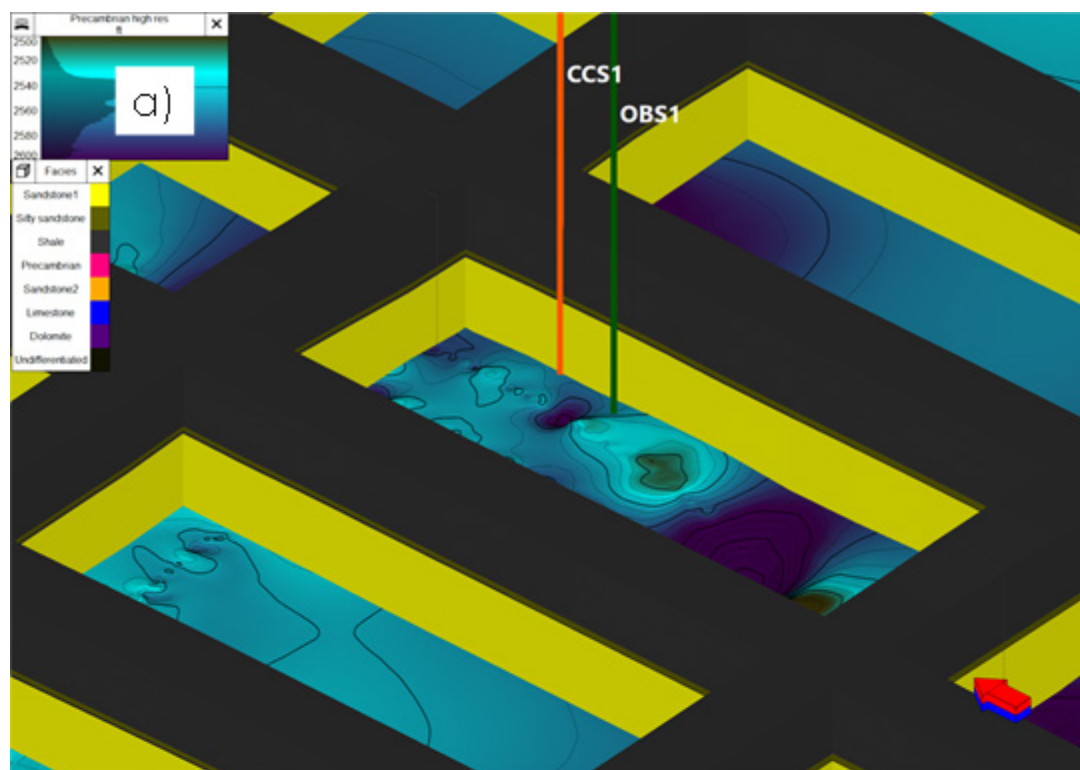












From CMG's GEM Users Manual:

## Introduction to GEM

### Introduction

In enhanced recovery schemes involving gas or solvent injection, the process may be immiscible or miscible depending on the composition of the injected fluid and the reservoir oil, and on the reservoir pressure and temperature. Examples of such processes are enriched gas drive, high pressure gas drive, CO<sub>2</sub> flooding, and the cycling of a gas condensate reservoir. The simulation of these processes requires special handling of both the thermodynamic and the fluid flow aspects of the reservoir.

GEM is an efficient, multidimensional, equation-of-state (EOS) compositional simulator which can simulate all the important mechanisms of a miscible gas injection process, i.e. vaporization and swelling of oil, condensation of gas, viscosity and interfacial tension reduction, and the formation of a miscible solvent bank through multiple contacts.

Some of the additional features of GEM are listed in the following.

### Adaptive Implicit Formulation

GEM can be run in explicit, fully implicit and adaptive implicit modes. In many cases, only a small number of grid blocks need to be solved fully implicitly; most blocks can be solved explicitly. The adaptive implicit option selects a block's implicitness dynamically during the computation and is useful for coning problems where high flow rates occur near the wellbore, or in stratified reservoirs with very thin layers. Several options are provided for selecting implicit treatment.

### Properties

GEM utilizes either the Peng-Robinson or the Soave-Redlich-Kwong equation of state to predict the phase equilibrium compositions and densities of the oil and gas phases, and supports various schemes for computing related properties such as oil and gas viscosities.

The quasi-Newton successive substitution method, QNSS, as developed at CMG, is used to solve the nonlinear equations associated with the flash calculations. A robust stability test based on a Gibbs energy analysis is used to detect single phase situations. GEM can align the flash equations with the reservoir flow equations to obtain an efficient solution of the equations at each timestep.

CMG's WinProp equation of state software can be used to prepare EOS data for GEM.

### Complex Reservoirs

GEM uses CMG's Grid Module for interpreting the Reservoir definition keywords used to describe a complex reservoir. Grids can be of Variable Thickness - Variable Depth type, or be of corner-point type, either with or without user-controlled Faulting. Other types of grids, such as Cartesian and Cylindrical, are supported as well as locally Refined Grids of both Cartesian and Hybrid type. Note that Hybrid refined grids are of a locally cylindrical or elliptical nature that may prove useful for near-well computations.

Regional definitions for rock-fluid types, initialization parameters, EOS parameter types, sector reporting, aquifers, ... are available. Initial reservoir conditions can be established with given gas-oil and oil-water contact depths. Given proper data (such as from WinProp), fluid composition can be initialized such that it varies with depth. A linear reservoir temperature gradient may also be specified.

Aquifers are modelled by either adding boundary cells which contain only water or by the use of the analytical aquifer model proposed by Carter and Tracy.

Dual porosity modelling can be done with GEM. Each cell is assigned separate matrix and fracture pore spaces. Shape factors describing flow between porosities are implemented based on the work of Gilman and Kazemi. Additional transfer enhancements are available to account for fluid placement in the fractures. The GEM user can also specify a dual permeability model which allows fluid flow between adjacent matrix blocks. This option is useful when matrix-matrix mass transfer processes are important, such as in situations dominated by gas-oil gravity drainage processes.

### **Geomechanical Model**

Several production practices depend critically on the fact that the producing formation responds dynamically to changes in applied stresses. These include plastic deformation, shear dilatancy, and compaction drive in cyclic injection/production strategies, injection induced fracturing, as well as near-well formation failure and sand co-production. A geomechanical model consisting of three submodules is available for treating aspects of the above problems. The coupling between the geomechanical model and the simulator is done in a modular and explicit fashion. This increases the flexibility and portability of the model, and decreases computational costs.

### **Wells**

Bottomhole pressure and the block variables for the blocks where wells are completed are solved fully implicitly. If a well is completed in more than one layer, its bottomhole pressure is solved in a fully coupled manner; i.e., all completions are accounted for. This eliminates convergence problems for wells with multiple completions in highly stratified reservoirs.

A comprehensive well control facility is available. An extensive list of constraints (maximum/minimum bottomhole or wellhead pressures, rates, WCUTs, GORs, ...) can be entered. As constraints are violated, new constraints can be selected according to the user's specifications. Various actions and apportionments are available.

Up to three hydrocarbon streams can be controlled on the surface: Oil, Intermediate Liquid and Gas. Various types of surface separation facilities can be used to generate these streams, including the modelling of EOS and plant separator stages, where the latter are described using key-component tables.

The gas cycling option in GEM allows for the preferential stripping of components and the addition of a make-up gas stream to the recycling gas stream.

### **Matrix Solution Method**

GEM uses AIMSOL, which is a state-of-the-art linear solution routine based on incomplete Gaussian Elimination as a preconditioning step to a GMRES iteration. AIMSOL has been developed especially for adaptive implicit Jacobian matrices.

For almost all applications, the default control values selected by GEM will enable AIMSOL to perform efficiently. Thus, GEM users do not require detailed knowledge of the matrix solution methods.

GEM uses run-time dimensioning as well to make the most efficient use of computer resources.

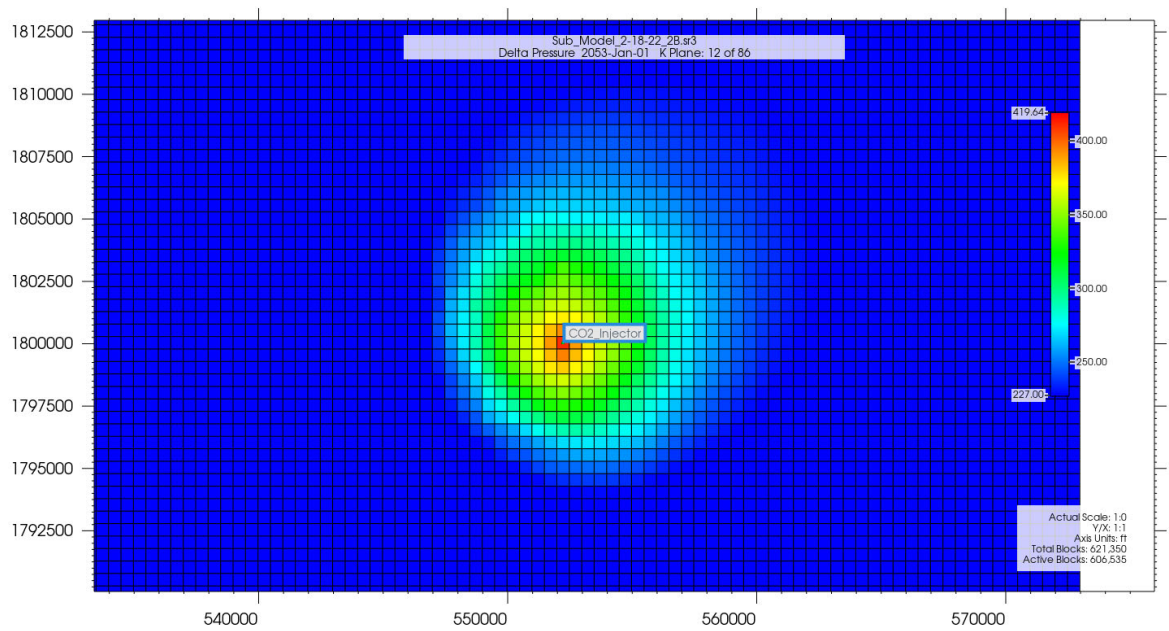
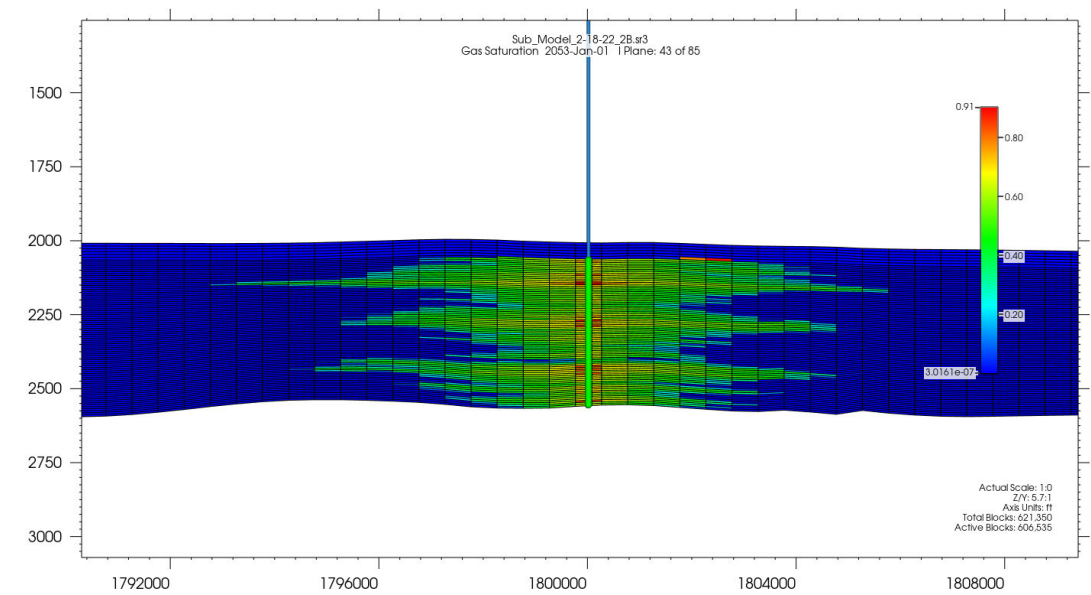
### **Simulation Results Files**

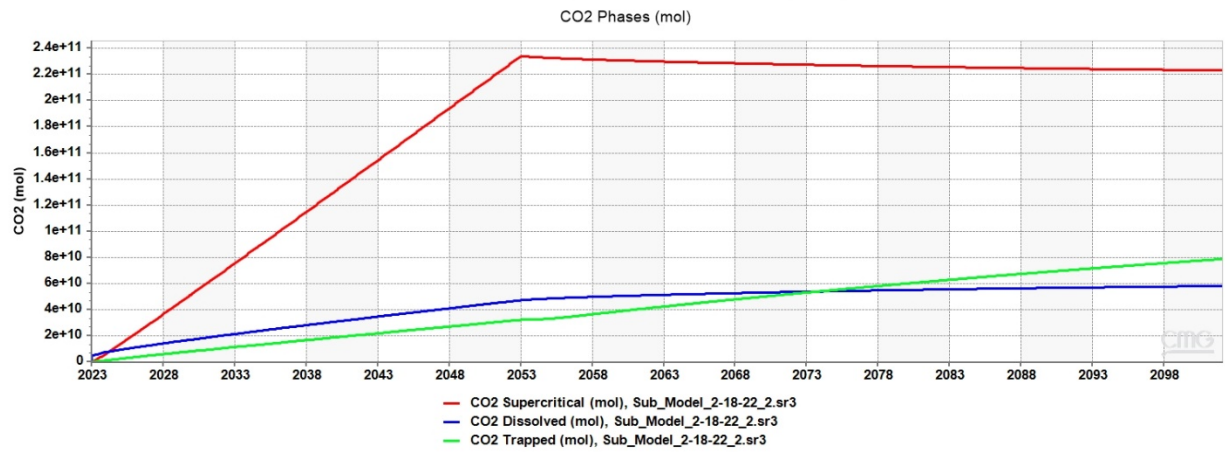
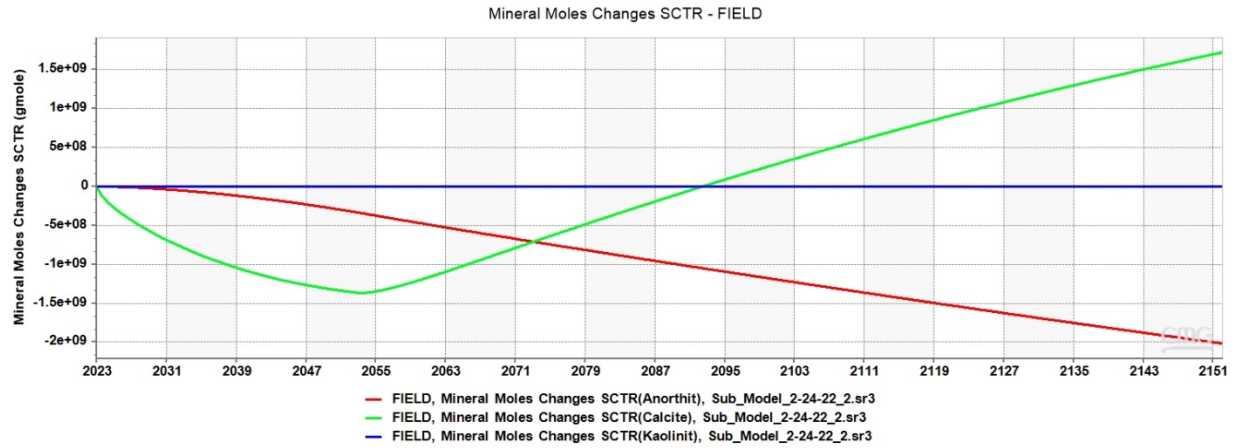
Various types of Simulation Results Files can be written while GEM is running, including files for CMG's Results. Results is CMG's visualization software that can be used to examine 2-D and 3-D reservoir displays, as well as XY plots of important dynamic data.

### **Portability**

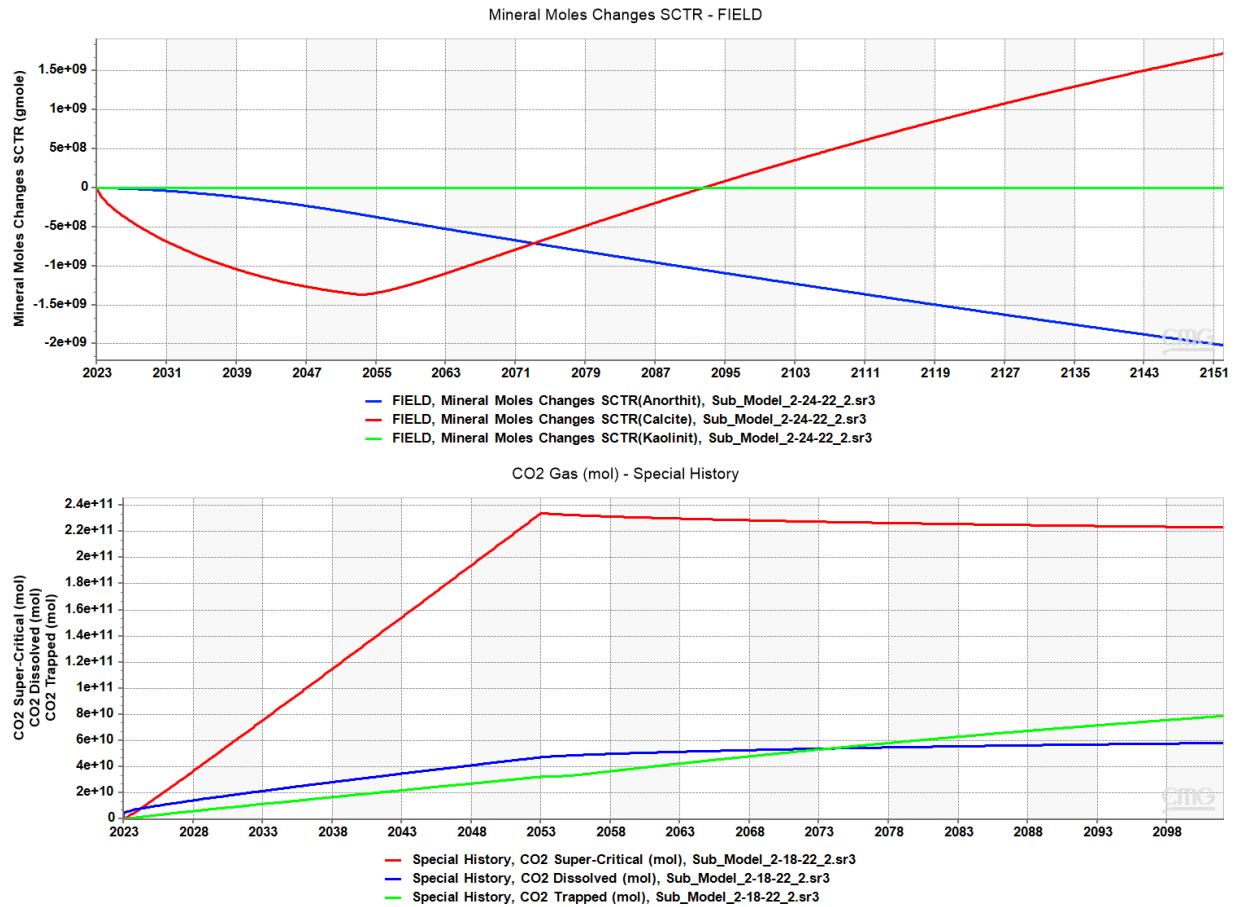
GEM has been run on many computers from many manufacturers, such as IBM, SGI, and SUN, as well as PCs. Currently supported chips and operating systems are given in the Installation Guide.

Model snapshot data showing the CO2 and pressure plumes after 30 years of injection.





Time series data showing the mineralization process over 100 years post injection, and the percentage of CO<sub>2</sub> Super-Critical, CO<sub>2</sub> dissolved, and CO<sub>2</sub> Trapped over 50 years post injection.



**Financial Assurance**  
**40 CFR 146.85**

**Hoosier #1 Project**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
Cardinal Ethanol

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CO<sub>2</sub> Injection Well Location for CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

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## Acronyms

3D	Three-dimensional
AFE	Authorization for Expenditure
AoR	Area of Review
CaCO <sub>3</sub>	Calcium Carbonate
CCS	Carbon Capture and Sequestration
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CO <sub>2</sub>	Carbon Dioxide
EPA	Environmental Protection Agency
ERR	Emergency and Remedial Response
ERRP	Emergency and Remedial Response Plan
IEc	Industrial Economics
MCLs	maximum contaminant levels
NPDWRs	National Primary Drinking Water Regulations
NSDWRs	National Secondary Drinking Water Regulations
O&G	Oil and Gas
OBS1	Deep Observation Well
OCF	One Carbon Partnership, LP
P&A	Plugging and Abandonment
PISC	Post Injection Site Care
RCRA	Resource Conservation Recovery Act
RO	Reverse Osmosis
SDWA	Safe Drinking Water Act
SMCL	secondary maximum contaminant level
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
VHM	volcanic, hydrothermal, and metamorphic

## 1 Introduction

The financial assurance for Class VI projects consists of these four components:

1. Corrective Action,
2. Injection Well Plugging and Abandonment (P&A),
3. Post Injection Site Care (PISC) and Site Closure,
4. Emergency and Remedial Response Plan (ERRP).

One Carbon Partnership, LP (OCP) contracted with Industrial Economics to assist with the ERRP component of the financial assurance package. All other components of the financial assurance assessment were performed by OCP.

This portion of the application discusses the methodology of determining the costs for each of the components, the financial responsibility instrument to be used, and the frequency with which the financial assurance will be reassessed.

## 2 Corrective Action Cost

The Corrective Action financial package consists of two components:

1. The cost to remediate any wells within the Area of Review (AoR) that penetrate the confining zone,
2. The cost to reassess the AoR.

There are no wells within the AoR that currently require corrective action. No wells within the AoR penetrate the confining zone (Attachment 2: AoR and Corrective Action, 2022). As such, there is no cost associated with remedial action for wells that penetrate the confining zone within the AoR. Any corrective action to wells associated with the project which penetrate the confining zone, are covered in the ERRP section of this document (Attachment 10: ERRP, 2022).

As discussed in the AoR Section, the AoR will be reevaluated every five (5) years. Based on the maximum anticipated project life of 30-years, the AoR will be reevaluated a minimum of six (6) times. Using an estimated cost of \$33,000 (2022 dollars) to reevaluate the AoR, the total cost for reevaluation over the project lifetime, accounting for an average inflation 5%, will be \$505,409 (2022 dollars). The calculations used to determine this value are provided in Table 1 below.

Table 1. Corrective Action Financial Assurance Cost Breakdown per Year	
Year	Cost (USD, 2022)
2027	\$42,117
2032	\$53,754
2037	\$68,605
2042	\$87,559
2047	\$111,759
2052	\$142,624
<b>Total</b>	<b>\$506,418</b>

These values were provided from a quote assembled by Subsurface Dynamics, based in Calgary, Alberta, Canada.

### 3 Injection Well Plugging Cost

The Injection Well Plugging Plan discusses the plugging plan in detail (Attachment 8: Well Plugging, 2022). To summarize the P&A program:

- Mechanical integrity logging will be performed prior to field mobilization or other plugging activities.
- CO<sub>2</sub> resistant materials and cement will be used to plug the well.
- The well will be plugged using cement retainers in the section of the well in which CO<sub>2</sub> resistant materials will be used, and balanced plugs will be used in the rest of the well.

The estimated P&A cost for the injection well, CCS1, is \$250,000 (Attachment 8: Well Plugging, 2022). Further details, schematics, and technical standards for the well plugging can be found in the Injection Well Plugging Plan.

A detailed Authorization for Expenditure (AFE) assembled from external quotes are provided as supplemental documentation along with the external quote.

#### 4 PISC and Site Closure Cost

The PISC and Site Closure Plan is discussed in Section 9 of this application (Attachment 9: Post-Injection Site Care, 2022). This section covers all activities that will occur following the conclusion of the injection activities. It is noted that OCP plans to pursue an alternative post closure time frame of 10 years. Justification for this alternative time frame is provided the PISC and Site Closure Plan. It is noted that based on current modeling, the CO<sub>2</sub> plume will stabilize two years after injection operations cease.

The PISC and Site Closure Plan covers the following activities:

(Note: This is not an exhaustive list.)

- Post injection monitoring
  - Logging
  - Pressure monitoring
  - Three-dimensional (3D) Seismic Surveys
- Monitoring well P&A
  - Deep Observation Well (OBS1)
  - ACZ1
- Assurance of continued non-endangerment of Underground Sources of Drinking Water (USDW)
  - Fluid sampling

Based on average annual cost projections of \$238,000 per year for the post injection monitoring period of ten years (it should be noted that after the plume is shown to be shrinking, monitoring activities will be performed less frequently, as discussed in the PISC section), the total cost for the post-injection monitoring is anticipated to be \$2,380,000, which includes seismic survey costs. Seismic surveys will be acquired twice during the ten-year PISC period. This cost was determined using external quotes. The external quotes for this work are provided.

Based on cost projections and the AFE's assembled for the project, the cost to plug the monitoring wells associated with the project are as follows:

- OBS1 - \$175,000
- ACZ1 - \$90,000

Total cost \$265,000.

Prior to and throughout the injection phase of the project groundwater samples will be routinely taken to assess the water quality and to determine if any variation from the baseline data set has occurred (Attachment 7: Testing And Monitoring, 2022). Water quality will continue to be assessed throughout the PISC portion of the project. Water will be sampled and analyzed twice per year for the first five years of the closure period, and once per year for the remainder of the closure period. This results in a total of 15 tests per well for the entirety of the ten-year closure period.

Currently twelve shallow groundwater wells are planned, along with one (1) deep groundwater well, one (1) above confining zone well, one (1) deep observation well, and the injection well. This is a total of 16 wells. Assuming 15 tests are performed on each well, a total of 240 tests will be performed. Based on Industrial Economic's assumption a single test costs \$200, a total of \$48,000 is planned for the fluid sampling portion of the PISC and site closure section of the financial assurance.

This includes the cost to access the wells and take samples, as well as the transportation, holding, and testing of the samples. Specifications on the methodology, storage, and transportation of the groundwater samples.

Table 2 displays the individual components of the PISC and site closure cost estimates, as well as the total projected cost for the PISC and site closure component of the financial assurance.

**Table 2. PISC Financial Assurance Cost Breakdown**

<b>Component of Financial Assurance</b>	<b>Amount of Funding</b>
Post Injection Monitoring	\$2,380,000
Monitoring Well P&A	\$265,000
Groundwater Sampling	\$48,000
<b>Total</b>	<b>\$2,693,000</b>

## 5 Emergency and Remedial Response Costs

This section summarizes estimates of emergency and remedial response (ERR) costs for the OCP Hoosier #1 Project (hereinafter, “Hoosier #1”). These estimates are consistent with the United States Environmental Protection Agency’s (EPA’s) Underground Injection Control (UIC) Program’s Class VI regulatory requirements and are intended to inform the face value of financial assurances necessary to satisfy ERR actions.

Estimating possible emergency and remedial cost estimates for Carbon Capture and Sequestration (CCS) necessitates an understanding of the interaction of the CO<sub>2</sub> stream and the subsurface environment in which it will be stored. The long-term nature of such projects, the low (but not zero) probability of a release event occurring that may require ERR, variability in potential incident conditions at the site, and the size of the potentially impacted population including likely exposure pathways inform the following ERR cost estimates.

As described in more detail below, we combine readily available information with the results of Monte Carlo analysis tailored to project-specific risks and uncertainties to generate reasonable upper bound estimates of ERR costs. In our view, the following cost estimates provide a reasonable, conservative, and objective basis for determining the face value of financial assurance instruments necessary to support a Class VI permit.

Importantly, the cost estimation method applied to Hoosier #1 is based on the peer-reviewed approach pioneered by Industrial Economics, Incorporated (IEC); this approach has been used to inform estimation of ERR costs in a previously approved Class IV permit.<sup>1</sup> IEC tailored the valuation parameters of its CCSvt Model to reflect site-specific factors associated with Hoosier #1. Specifically, the Model’s input parameters reflect the geologic location and specific chemical composition of Hoosier #1’s CO<sub>2</sub> stream, as well as the site-specific conditions that exist within the established AoR. The analysis adopts several conservative input assumptions and incorporates probabilistic calculations that allow for multiple release incidents through operation, closure, and post-injection site care. Cost estimates are based upon generally accepted response actions commonly used to respond to contamination incidents that could impair the public’s ability to safely access USDWs.

Based on a model run of 50,000 Monte Carlo trials, an upper-bound cost estimate of \$2.7 million in current 2022 dollars is arrived at to satisfy ERR. This estimate specifically accounts for an array of possible risk events of potential concern at CCS sites, including undocumented deep well leaks, a CO<sub>2</sub> injection well leak, rapid leakage through the caprock, slow leakage through the caprock, release through an existing fault, release through an induced fault, and leakage through the caprock (or fault) followed by leakage through a shallow well. The upper-bound cost estimate reflects the single Monte Carlo trial with the greatest emergency and remedial costs out of the 50,000 trials run.

In the sections that follow the basis for the cost estimates is discussed in greater detail.

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<sup>1</sup> This approach informed the Class VI permit application for Red Trail Energy, LLC, also an Ethanol producer, in North Dakota. See Trabucchi, C., Donlan, M., Huguenin, M., Konopka, M., Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012. See also, Trabucchi, C., Donlan, M. and Wade, S., 2010 ‘A multi-disciplinary framework to monetize financial consequences arising from CCS projects and motivate effective financial responsibility’, International Journal of Greenhouse Gas Control 4 (2010) 388-395 and Trabucchi, C., Donlan, M., Sprit, V., Friedman, S. and Esposito, R., 2014, ‘Application of a Risk-Based Probabilistic Model (CCSvt Model) to Value Potential Risks Arising from Carbon Capture and Storage’, Energy Procedia 63 (2014) 7608-7618.

## 5.1 USDW Non-Endangerment

The Safe Drinking Water Act (SDWA) was established to protect the quality of drinking water in the United States. The law focuses on all waters designed for drinking use, whether from above ground or underground sources (42 U.S.C. §§300f-300j-26). The concept of ‘endangerment’ (as it relates to the UIC Program) is defined further in the federal code of regulations, which states: “No owner or operator shall construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 142 or may otherwise adversely affect the health of persons” (40 CFR 144.12).

National Primary Drinking Water Regulations (NPDWRs) establish mandatory water quality standards for drinking water contaminants. These standards are referred to as “maximum contaminant levels” (MCLs), which are intended to protect the public against consumption of drinking water contaminants that present a risk to human health. An MCL is the maximum allowable amount of a contaminant in drinking water delivered to the consumer.

National Secondary Drinking Water Regulations (NSDWRs) set non-mandatory water quality standards for 15 contaminants. These standards are offered as guidelines to assist public water systems in managing their drinking water for aesthetic considerations, such as taste, color, and odor. These contaminants are not considered to present a risk to human health at the secondary maximum contaminant level (SMCL) (United States Environmental Protection Agency, 2022).

Consistent with these mandates, potential consequences arising from CO<sub>2</sub> release incidents resulting from the Hoosier #1 Project were be evaluated, which could result in an exceedance of one or more MCLs in a USDW. This is done, because, however unlikely, it is possible that such incidents could result in the need for an ERR action. Evaluation of potential consequences begins with the composition of the CO<sub>2</sub> stream and the potential pathways for harm to USDWs.

- Composition of the CO<sub>2</sub> stream. The Hoosier #1 CO<sub>2</sub> stream will originate from the Cardinal Ethanol manufacturing facility. The most recent feed gas test report (see Figure 3) indicates that the composition of the CO<sub>2</sub> stream will be close to pure CO<sub>2</sub> (99.8% by volume). The Indiana Department of Environmental Management identifies 76 contaminants for which MCLs have been established in Indiana (Indiana Department of Environmental Management, 2022). None of the identified compounds are detectable in the Hoosier #1’s CO<sub>2</sub> stream.

Potential Pathways for Harm to USDWs. The composition of the close-to-pure CO<sub>2</sub> stream suggests that a release, should it occur, will not directly introduce contaminants into a USDW that results in an exceedance of an MCL. Nonetheless, indirect harm is possible. Conceptually, a CO<sub>2</sub> release into a USDW could reduce pH sufficiently to increase the leaching of heavy metals from aquifer minerals at concentrations that exceed an MCL. For completeness, it is noted that there are secondary drinking water standards with potential relevance, for example pH (between 6.5 and 8.5) and total dissolved solids (500 mg/l), but the types and scale of ERR actions incorporated in this analysis to address potential exceedances of metals MCLs would, at the same time, address the aesthetic impacts associated with potential exceedance of SMCLs

## 5.2 Monte Carlo Approach to Cost Estimation

The cost of ERR is estimated by tailoring the valuation parameters underpinning the CCSvt model to reflect site-specific factors associated with Hoosier #1. The CCSvt model published in the peer-reviewed technical literature leverages Monte Carlo (i.e., risk-based, probabilistic) modeling and site-specific scenario analysis (Trabucchi et al., 2014). In our view, Monte Carlo analysis is particularly well suited to the evaluation of potential costs arising from low probability events over long periods of time. As described in Trabucchi et. al (2014), key parameters which inform the CCSvt model inputs include identification of release event types and probabilities, the duration of injection and PISC activities, and cost distributions for anticipated response actions if a release occurs.

## 5.3 Area of Review

The information and analyses underpinning ERR cost estimation reflect an Area of Review that extends 2.5 miles in all directions from the anticipated injection location. Please note that this 2.5-mile AoR used differs from the 2.26-mile AoR utilized for the rest of the permit application; the use of a 2.5-mile AoR results in a more conservative ERR cost estimation.

## 5.4 Risk Event Types and Probabilities

Table 3 identifies the risk event types and probabilities used to estimate ERR costs for Hoosier #1. Annual release probabilities are based on the Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement, revised April 2007 (FutureGen, 2007, pp. 6-15). These data reflect extensive, federally funded analysis, are publicly available, and informed development of an Analog Site Database regarding the release of CO<sub>2</sub> from existing injection sites and natural releases.<sup>2</sup> The Analog Site Database includes information from four existing CCS sites, 16 natural CO<sub>2</sub> sites in sedimentary rock formations, and 17 sites in volcanic, hydrothermal, and metamorphic (VHM) areas. These sites have been identified in several natural analog investigations for CCS.

In addition to leakage from reservoirs via natural pathways, the FutureGen efforts considered leakage information from a myriad of CCS risk assessments and developed a well failure-release event database, which reflects applied experience from the natural gas storage industry, the oil and gas (O&G) industry, and wells at natural CO<sub>2</sub> reservoirs.

Estimates of potential consequences at Hoosier #1 are informed by the annual probability point estimates resulting from the FutureGen efforts. In some cases, FutureGen provides a range of probabilities – in such circumstances, we conservatively use the highest probability in the range. Table 3 reflects the release probabilities for seven types of risk events. For well-related events, the identified probabilities reflect the risk of release for a single well.

To accommodate site-specific evaluation of Hoosier #1, IEC adapted its CCSvt model to account for the specific number of wells and well types in the AoR, based on site-specific information from the Indiana Oil & Gas Online Well Records Database. Importantly, we also refine the underlying CCSvt modeling parameters to include an “undocumented deep well leak” risk event category.

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<sup>2</sup> Ibid, pg 5-1.

**Table 3. Risk Event Types and Probabilities**

Risk Event Type	Annual Probability	Number of Wells
Undocumented Deep Well Leak	0.1% per well <sup>a</sup>	2
CO <sub>2</sub> Injection Well Leak	0.001% per well <sup>b</sup>	1
Rapid Leakage Through Caprock	0.0000002% <sup>c</sup>	n/a
Slow Leakage Through Caprock	0.004% <sup>d</sup>	n/a
Release Through Existing Faults	0.000002% <sup>e</sup>	n/a
Release Through Induced Faults	0.000002% <sup>f</sup>	n/a
Leakage Through Caprock/Faults then Shallow Well	0.008% <sup>g</sup>	10
Source for risk events and annual probabilities: Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement, revised April 2007, available online at: <a href="https://www.energy.gov/sites/prod/files/EIS-0394-DEIS-RiskAssessmentReport-2007.pdf">https://www.energy.gov/sites/prod/files/EIS-0394-DEIS-RiskAssessmentReport-2007.pdf</a> , p. 6-15, Table 6-11.		
Additional Notes:		
a) Highest probability within FutureGen range for undocumented deep wells developed from the FutureGen analog database.		
b) Highest probability within FutureGen range for CO <sub>2</sub> injection wells developed from the FutureGen analog database.		
c) Equal to FutureGen probability for rapid leakage through caprock developed from the FutureGen analog database.		
d) Equal to FutureGen probability for slow leakage through caprock developed from the FutureGen analog database.		
e) Equal to FutureGen probability for release through existing faults developed from the FutureGen analog database.		
f) Equal to FutureGen probability for release through induced faults developed from the FutureGen analog database.		
g) Conservatively assumed to be twice as likely as the highest caprock/fault probability.		

To be clear, the Indiana Oil & Gas Online Well Records Database indicates that there are no wells in the AoR deep enough to penetrate the confining zone. Ten shallow O&G wells are identified in the database, but at depths hundreds of feet short of the confining zone. Water wells in the AoR are all at depths less than approximately 300 feet (Attachment 2: AoR and Corrective Action, 2022).

Notwithstanding our extensive records review, the possibility cannot be ruled out that records may be incomplete, and construction or natural landscape features may obscure old well locations. To account for this, albeit unlikely, possibility our cost estimation conservatively presumes the existence of two undocumented deep wells (i.e., deep enough to penetrate the confining zone of the injection zone). We assume two such wells based on the following factors:

- Publicly available records of O&G wells in Indiana span several decades. Notably, these records indicate that the oldest of the ten identified wells in the AoR was constructed in 1903.
- The presence of ten active or abandoned O&G wells in the AoR demonstrates that O&G exploration and/or production has occurred, but at relatively minor levels. The AoR is not in a location characterized by extensive O&G activity, based on well records.
- The Indiana Department of Natural Resources Division of O&G indicates that, historically, central and eastern Indiana O&G development has focused on the Trenton formation. This formation is an Ordovician age limestone with an average thickness of 100 feet, found at an average depth of 900 feet in 21 counties in Indiana. Storage at the Hoosier #1 CCS site will occur at a depth of over 3,000 feet – at a depth substantially deeper than that historically applied by O&G exploration and production companies.

Notwithstanding, we include two undocumented deep wells in our evaluation of Hoosier #1 – equivalent to 20 percent of the number of known active and/or abandoned shallow O&G wells,

because no deep injection wells have been found within the AoR. We believe this approach is reasonable and conservative.

The FutureGen efforts do not provide release probability estimates for shallow industrial wells that do not penetrate confining zone. For purposes of estimating ERR costs for Hoosier #1, we assume that shallow industrial wells that do not penetrate the confining zone have a release probability equal to twice the highest probability for confining zone or fault release events. This assumption reflects the fact that CO<sub>2</sub> would need to escape through the confining zone or fault before reaching the shallow industrial well, at which point the well may yield a more direct pathway to a USDW. We believe this approach is reasonable and conservative.

## **5.5 Duration Of Injection and PISC Activities**

OCP cost estimation protocol reflects a 30-year CO<sub>2</sub> injection period and a 30-year PISC period. Consistent with these assumptions, the Monte Carlo calculations incorporate a 60-year (30 years injection, 30 years PISC) project duration. This approach is reasonable and conservative, and as addressed in other parts of the permit application, a 10-year PISC is anticipated to be sufficient to demonstrate stabilization of sequestered CO<sub>2</sub>.

## **5.6 Cost Distributions if a Release Occurs**

Although previous peer-reviewed, published applications of the CCSvt model relied on 10,000 Monte Carlo trials, for this analysis we ran 50,000 Monte Carlo trials to provide additional certainty. If a release event occurs during a Monte Carlo trial, the model randomly chooses a cost amount for the indicated response activity from the cost distributions described below.

### **5.6.1 Well Repair Cost Distribution**

- Minimum: \$5,000
- 10<sup>th</sup> percentile: \$8,100
- Median: \$56,000
- 90<sup>th</sup> percentile: \$170,000
- Maximum: \$500,000

This cost distribution is applied to release events associated with well repair – to stop leaks and prevent reoccurrence. As indicated in Table 3, the most likely well-related release event (by at least two orders of magnitude) is the ‘undocumented deep well’ category. Any release of CO<sub>2</sub> through such wells likely would involve plugging and surface reclamation. Information and analysis provided in Raimi et al (Raimi, 2021) is relied upon as a proxy for such costs. This peer-reviewed, publicly available analysis provides cost estimates for plugging and surface reclamation of O&G wells, based on data from up to 19,500 wells.

The 10<sup>th</sup> percentile, median, and 90<sup>th</sup> percentile costs are from Raimi et al (2021). A minimum cost of \$5,000 is applied, notwithstanding the fact that costs below this amount were observed in the data set. The maximum value of \$500,000 reflects the highest cost for wells with depths up to approximately 3,000 feet – the top of the injection zone for Hoosier #1 is expected to be at a depth of approximately 3,100 feet, and as previously noted all known wells in the AoR are at shallower depths. Accordingly, these assumptions are reasonable and conservative.

### ***5.6.2 USDW Contamination Incident Cost Distribution***

- Minimum: \$50,000,
- Maximum: \$1,040,000,
- Uniform distribution.

This cost distribution is applied to all release events (and the resulting costs are added to well repair costs for well-related events). This distribution reflects several different response components, including characteristics of USDW use in the AoR for Hoosier #1, as well as the professional judgement of experts versed in federal and state response action to groundwater contamination incidents. The underlying basis for this cost distribution is described following.

Figure 1 is a Google Earth image that provides visual representation of the land use above the CCS injection zone. The approximate location of Hoosier #1's proposed injection well is identified by the blue star. As can be seen from this image, land use in the area of concern is generally rural with agricultural activity and few scattered residences.

Union City is approximately one mile to the east of the anticipated injection location; currently, Union City has an estimated population of approximately 3,454 (Stats Indiana, 2020). The population appears to have declined modestly relative to 1990, when its population was approximately 3,612.

Figure 2 illustrates the location of water wells and O&G wells within, and just outside, a 2.5-mile radius of the approximate location of the proposed Hoosier #1 Class VI injection well. As previously indicated, there are 10 abandoned or active O&G wells within the 2.5 miles of the proposed injection well. In addition, there are approximately 200 water wells located within proximity of the AoR, all of which are at depths of approximately 500 feet or less.

The Union City Water Works provides public water to 3,513 people. The source of Union City's drinking water is groundwater produced from seven production wells in two well fields located in proximity to Union City, but outside of the AoR. The South Water Plant Well Field is the primary source of drinking water (The City of Union City, Indiana, 2022).

Examination of Indiana Department of Natural Resources water well database records reveals water quality data for one (private) well within a 2.5-mile radius from the planned injection well, and for several wells within ten miles of Hoosier #1's planned injection location. Specifically, Union City's 2020 water quality report reveal maximum metals levels to be less than one-third of relevant MCLs. In general, data from the Indiana water well database indicates that metals levels at water quality wells within ten miles of the planned injection well (maintained by either Indiana or United States Geological Survey) were an order of magnitude or more below relevant MCL.

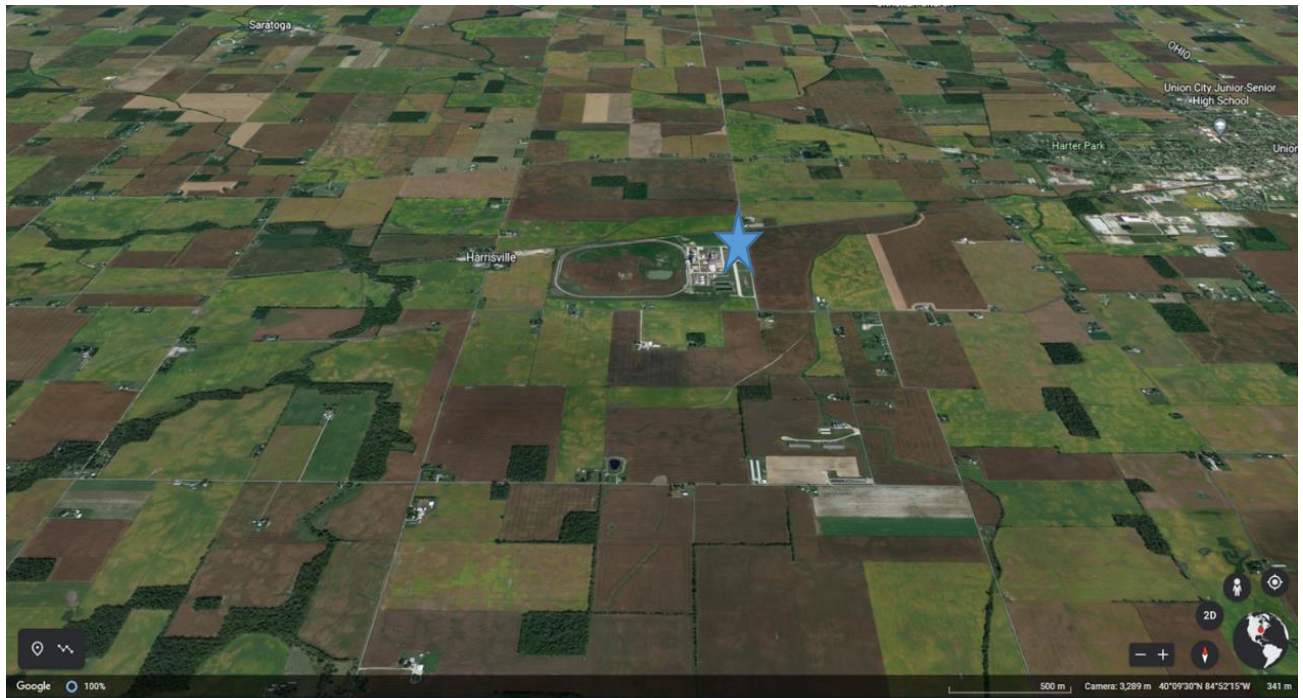


Figure 1. Land Use Above Hoosier #1 Project

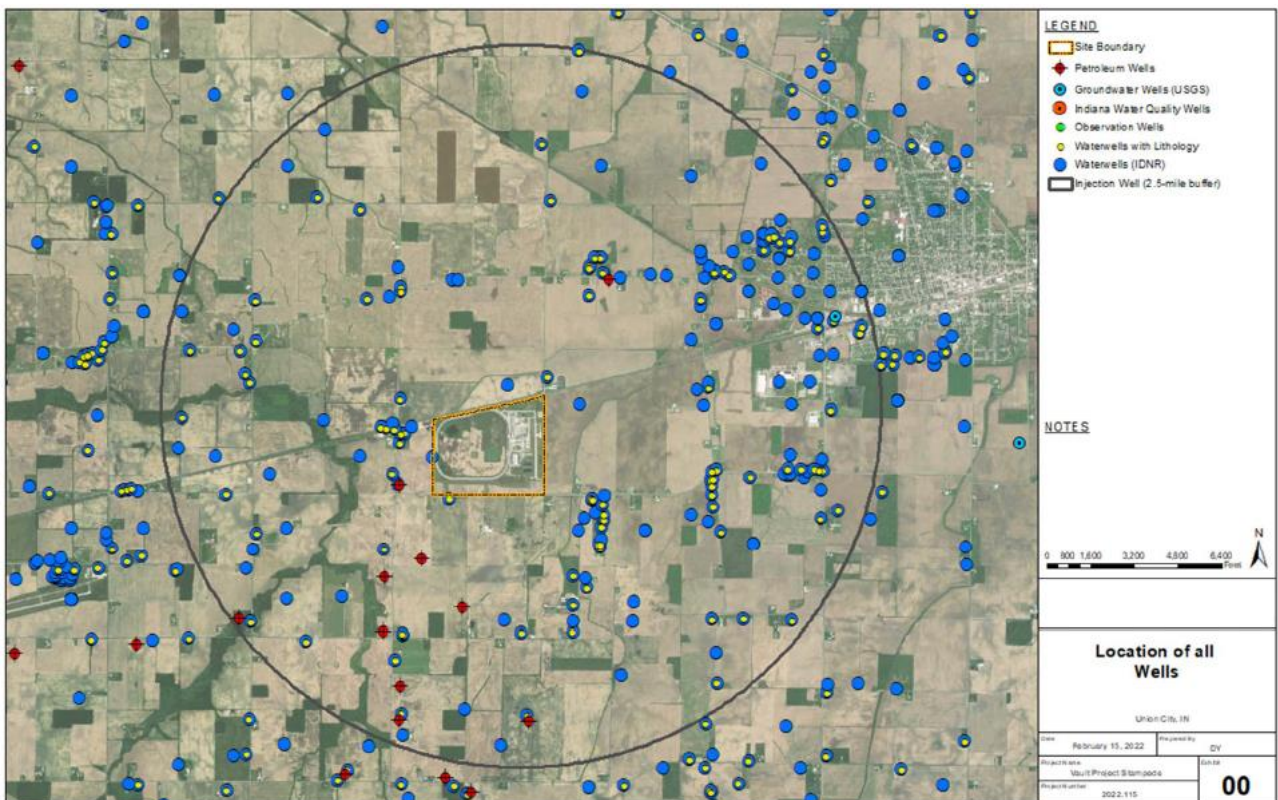


Figure 2. Water and O&G wells in the proximity to the Hoosier #1 Project

Consistent with these site-specific parameters, a maximum per-incident cost range has been tailored to Hoosier #1 and estimated as follows:

- A maximum of \$30,000<sup>3</sup> to drill new water monitoring wells, to facilitate data collection to evaluate the spatial extent, existence, and/or significance of a potential release-related plume,<sup>4</sup> plus
- A maximum of \$80,000<sup>5</sup> for quarterly sampling and analysis for standard field measurements and heavy metals at an estimated \$200 per sample,<sup>6</sup> including collection and analysis, for up to two years and (conservatively) 50 residences,<sup>7</sup> plus
- A maximum of \$20,000<sup>8</sup> for residential replacement water for one year for up to 50 residences,<sup>9</sup> plus
- A maximum of \$125,000<sup>10</sup> for purchase and installation of residential reverse osmosis (RO) units at up to 50 residences,<sup>11</sup> plus

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<sup>3</sup> \$30,000 = 4 wells \* 300 foot depth \* \$25 drilling cost per foot.

<sup>4</sup> At an estimated drilling cost of \$25 per foot (see <https://homeguide.com/costs/well-drilling-cost#cost>, which estimates a cost of \$15-\$25 per foot for drilling a water well), this cost allowance would allow, for example, drilling of four new wells at a 300-foot depth.

<sup>5</sup> \$80,000 = 50 residences \* 8 quarterly samples \* \$200 per sample.

<sup>6</sup> See for example information from laboratory vendor Chemtech international at <https://chemtech-us.com/articles/cost-of-well-water-testing-in-2021/#:~:text=It%20costs%20%24165%20at%20the,%24279%20at%20the%20full%20price>, which states “the Essential Water Test is a standard test that screens the general water chemistry, the hardness and alkalinity of the water, toxic and heavy metals, nitrates and nitrites, coliform and E. coli bacteria, and silica. It costs \$165 at the full price.” This is rounded up to \$200 to account for potential sample collection costs.

<sup>7</sup> If there is a release incident, a common response measure would be to periodically test water wells within the potential impact area to determine if any residences are at risk of exposure to contaminants at levels above an MCL. At this location, well-related incidents are by far the most likely types of events to potentially impact a USDW. It is reasonable to anticipate that faulty wells could be repaired, plugged, or otherwise addressed within a two-year time frame. As a result, testing of residential wells should be unnecessary after two years.

<sup>8</sup> \$20,000 = 50 residences \* \$35 per month for 25 gallons \* 12 months. (Rounded to \$20,000)

<sup>9</sup> If residential water well testing identifies contaminant levels of concern, replacement water for drinking and cooking would be provided for affected residents. Commercial companies offer water delivery service at approximately \$35 per month for 20 gallons, a typical consumption level for a family of 3 to 4 (see for example pricing and family water quantity recommendations from water vendor Culligan at <https://www.culligan.com/bottled-delivery/select>). Replacement water typically is a temporary measure; in this case, if contamination issues persist for longer than one year, it is anticipated that the replacement water program would end and be replaced by installation of residential RO units to provide clean water, which is a more expensive but more appropriate solution for longer term contamination issues.

<sup>10</sup> \$125,000 = 50 residences \* \$2,500 per RO unit.

<sup>11</sup> While some residential RO units (and other types of residential treatment technologies) can cost several hundreds of dollars, for this analysis, we assume installation of a Kinetico K5 Drinking Water Station RO unit, which is an RO model currently designated for use in response to a severe, long-term groundwater contamination incident in North Carolina, affecting thousands of residences (see <https://edocs.deq.nc.gov/WasteManagement/DocView.aspx?id=1636579&dbid=0&repo=WasteManagement>). Pricing information from Consumer Reports indicates that \$2,500 is a reasonable cost estimate for this unit.

- A maximum of \$75,000<sup>12</sup> for RO replacement filters, including servicing of such units at \$300 per unit per year for up to five years at 50 residences,<sup>13</sup> plus
- A maximum of \$200,000 for irrigation support,<sup>14</sup> plus
- A maximum of \$500,000 for additional potential unanticipated remedial and response actions,<sup>15</sup> plus
- A maximum of \$10,000 for supplemental sampling and analysis at Union City Water Works.<sup>16</sup>

Summing the maximum dollar amount for each of these components results in a total maximum per-release cost of \$1,040,000, in current 2022 dollars, for USDW contamination incident cost distribution tailored to Hoosier #1's circumstances. We rely on a minimum cost of \$50,000 for the cost distribution; this estimate reflects the, albeit unlikely, potential for small releases insufficient to cause measurable adverse impacts or to cause impacts which are easily addressed with minimal remedial action. We offer additional context for these estimates below.

In our view, generalized groundwater contamination at Resource Conservation Recovery Act (RCRA) or Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) sites are not the right analogs for Hoosier #1. First, these types of sites often contaminate groundwater through spatially broad-based infiltration from the surface above, originating from the release of hazardous substances directly or indirectly to land and/or surface water/sediments. Further, these types of sites can lead to complicated, long-lasting groundwater response and remediation

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<sup>12</sup> \$75,000 = 50 residences \* \$300 per RO unit per year \* 5 years.

<sup>13</sup> Annual RO unit maintenance costs will vary depending on water use, contaminant levels and other factors. Based on warranty information, replacement filter prices and professional judgement, \$300 per year per unit is a reasonable approximation of annual maintenance costs. As previously noted, release incidents that occur should be resolvable within two years. Out of an abundance of caution, for purposes of cost estimation, we assume maintenance of RO units for five years after installation to allow for natural dilution/dissipation of any residual CO<sub>2</sub>/low pH plume, supplemented by active remediation, if needed.

<sup>14</sup> Although Indiana averages about 40 inches of rain per year, irrigation sometimes is used particularly in summer months. It is difficult to forecast specific needs in response to a potential release event due to seasonal timing, weather, specific crop requirements, and other factors, \$200,000 provides a substantial sum that could be used for a variety of potential response activities, including but not limited to: funding a new irrigation system establishing connections to existing, unaffected wells; installing new wells in areas away from potential release impacts and connecting them to irrigation systems; instituting farm-specific treatment solutions; and providing temporary replacement water (trucked water can cost about \$30-\$65 per 1,000 gallons).

<sup>15</sup> As part of the ERR response to a release incident, actions might be needed to address CO<sub>2</sub> groundwater plumes, to limit plume movement, accelerate dilution of CO<sub>2</sub> concentrations, extract CO<sub>2</sub> through air stripping or other technologies, buffer pH, construct reactive barriers and/or otherwise speed the return of an impacted USDW to baseline conditions. This cost estimate reflects several factors likely to limit the magnitude of such costs: as discussed elsewhere in this document, CO<sub>2</sub> releases from faulty wells are attended to relatively quickly; resultant/residual CO<sub>2</sub> plumes are not likely to be large; rural land use patterns and the low density of water wells in the AoR limit the potential for plume impacts; dilution/natural attenuation will reduce CO<sub>2</sub> levels without intervention; and CO<sub>2</sub> is relatively inexpensive to remove from groundwater.

<sup>16</sup> The Indiana Oil & Gas Online Well Records Database reveals one abandoned well approximately one mile from Union City (see Figure 2). The Indiana Department of Natural Resources water well database records indicates that the Union City Water Works has seven intake wells (see Figure 4). In the unlikely event of a release, the utility may need to test its water more frequently for a defined period of time, and/or test its water for MCLs that are not part of its regular testing program (see <https://unioncity-in.com/misc-fact-pages#bf19eb4a-2f2e-4e41-a38d-fc8e7a3b12c5> for a recent Union City Water Works sampling report). At the approximately \$200 per sample cost previously identified for laboratory analysis, \$10,000 would provide sufficient funds for up to 50 additional supplemental samples. As a general matter, to the extent one or more of the utility's wells is impacted by a release event, a typical response action would be for the utility to rely on one of its other intake wells while any release-related issues are resolved.

measures, particularly when dealing with long-lived contaminants that can be difficult and expensive to remove.

In contrast, potential release events relevant to the Hoosier #1 site would originate thousands of feet **below** USDWs. By far, the most likely pathway for a potential release is through a CCS, O&G, or other industrial well. Such releases are associated with a very specific release location, which offer a much better opportunity to identify and mitigate infiltration impacts than a generalized groundwater contamination event.

Second, as previously noted, the composition of the Hoosier #1 CO<sub>2</sub> stream is predominantly pure CO<sub>2</sub> (99.8% by volume) with no co-constituents that could directly introduce contaminants into a USDW that could lead to an exceedance of a health based MCL. Rather, potential impacts from a release would occur indirectly by lowering groundwater pH, which, in turn, could lead to increased dissolution of metals present in the aquifer matrix.<sup>17</sup>

Importantly, however, there are natural factors that are likely to limit the impact of any released CO<sub>2</sub> on pH at the Hoosier #1 site. Specifically, area wells produce water from the shallow glacial deposit aquifer and from a deeper carbonate bedrock aquifer. The glacial origin of the shallow aquifer (100 feet) used by the community in the AoR is likely to have carbonate mineral material in the aquifer matrix. Carbonate will act to buffer pH from changes due to CO<sub>2</sub> – with a carbonate concentration of even 1% by weight, pH changes are unlikely to be meaningful. Likewise, the glacial aquifer (at depths greater than 100 feet) will have an abundance of carbonates which will serve to buffer the effects of the carbonic acid.

Although we have not obtained carbonate aquifer matrix measurements in or near the AoR, alkalinity measurements from groundwater quality wells within about ten miles of the planned injection well range from 300-500 mg/L as calcium carbonate (CaCO<sub>3</sub>). Alkalinity is a different measure of the capacity of water (or any solution) to neutralize or “buffer” acids. In general, the levels observed near the Hoosier #1 location are considered moderate or high, which indicate that meaningful buffering capacity exists.

Third, for harm to occur from a release event, there also needs to be a sufficient reservoir of metals in the aquifer matrix to be leached into USDWs to result in health based MCL exceedances. Local measurements of aquifer matrix concentrations of metals have not been obtained, but as previously noted, rural water quality wells within about 10 miles of the Hoosier #1 location generally are an order of magnitude or more below relevant MCLs.<sup>18</sup>

With respect to the potential number of residences that might be affected if a release event were to occur, evaluation of the Hoosier #1 site assumes a maximum of 50 households. This assumption reflects several factors. First, as previously noted, there are approximately 200 water wells in the entire AoR. However, nine of the ten active/abandoned industrial wells are in the southwest portion of the AoR; the attendant rural, low-density area of these wells is the most likely location for a release if a release were to occur. An impact plume in that area would need a radius in the order of one mile

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<sup>17</sup> To the extent naturally occurring brine also was released in an event, the emergency response and remediation actions incorporated into the Hoosier #1 evaluation would simultaneously address related impacts.

<sup>18</sup> Secondary (aesthetic) MCLs for iron and manganese are exceeded in the local area (and often in Upper Midwest locations). As a result, some residences and business might already have treatment systems in place to address related aesthetic impacts, which in some cases also might reduce potential impacts from a CO<sub>2</sub> release to a USDW. This Hoosier #1 evaluation conservatively assumes no such ‘pre-existing’ systems are in place. Separately, we note that the residential RO/comparable systems included in the Hoosier #1 cost distribution also would have the secondary benefit of removing iron and manganese from residential drinking water.

to affect as many as 50 water wells (see Figure 2), and likely would affect far fewer. For reasons described throughout this document, a CO<sub>2</sub> impact plume approaching that size is highly improbable. Notably, analyses in relevant published literature that attempt to forecast plausible potential CO<sub>2</sub> plume sizes at other locations generally describe radial CO<sub>2</sub> plume distances on the order of hundreds of meters or less – not thousands of meters.<sup>19</sup>

Finally, although it is recognized that there are deeper bedrock aquifers present below the glacial and the upper bedrock aquifers in the AoR contemplated for Hoosier #1, water quality data for these aquifers are not generally available. Importantly, however, it has been confirmed that all water wells in the AoR draw from shallow aquifers at depths of 500 feet or less. Given negative population growth in the Union City area over the past 30 years, coupled with substantial rainfall, the potential use of deeper, less productive, and more expensive water resources is unlikely. Nonetheless, in the unlikely event that a release incident related to Hoosier #1 were to occur and were to impact a deep aquifer, the emergency response and remediation actions associated with residential or agricultural water use could be repurposed to mitigate the release to the deeper USDW, because there is no residential or agricultural use of deeper aquifers in the AoR.

## 5.7 Emergency and Remedial Response Cost Estimation Results

Table 4 summarizes the results of the 50,000 Monte Carlo simulations that inform estimates of ERR costs for Hoosier #1. The estimated costs are broken down by risk event type in

Table 5. Table 6 identifies the number of trials with the identified characteristics.

Based on the Monte Carlo results an upper-bound cost estimate to satisfy ERR of \$2.7 million in current 2022 dollars determined. This determination specifically accounts for an array of possible risk events of potential concern at CCS sites, including undocumented deep well leaks, a CO<sub>2</sub> injection well leak, rapid leakage through the caprock, slow leakage through the caprock, release through an existing fault, release through an induced fault, and leakage through the caprock (or fault) followed by leakage through a shallow well. This upper-bound cost estimate reflects the single Monte Carlo trial with the greatest emergency and remedial costs out of the 50,000 trials run.

As described throughout this document, a substantial level of conservatism has been built into model inputs. For example, as indicated in

Table 5, more than half (63.5%) of all modeled costs relate to the risk event category ‘undocumented deep well leak’. For clarity, there is no actual evidence of any wells in the AoR deep enough to penetrate confining zone and, given the typical depths of O&G deposits in the area, it is highly unlikely any such deep wells were drilled. Nevertheless, out of an abundance of caution, we incorporate two such wells into our cost estimation for ERR actions.

**Table 4. ERR Simulation Results Summary**

Summary Statistic	Cost	Number of Events Occurring
Average	\$106,093	0.17
Median	\$0	0
Standard Deviation	\$286,243	0.41

<sup>19</sup> See for example Elizabeth Keating, D. Bacon, S. Carroll, K. Mansoor, Y. Sun, L Zheng, D. Harp and Z. Dai. Applicability of aquifer impact models to support decisions at CO<sub>2</sub> sequestration sites. International Journal of Greenhouse Gas Control 52 (2016) 319-330. and Nicholas Huerta, D. Bacon, C. Carman and C. Brown. NRAP Toolkit Screening for CarbonSAFE Illinois – Macon County. Illinois State Geological Survey Prairie Research Institute and Pacific Northwest National Laboratory. Report prepared for US DOE 00029381. 2020.

Summary Statistic	Cost	Number of Events Occurring
5 <sup>th</sup> Percentile	\$0	0
95 <sup>th</sup> Percentile	\$853,930	1
99 <sup>th</sup> Percentile	\$1,176,765	2
Minimum	\$0	0
Maximum	\$2,678,602	4

**Table 5. Cost Estimate Breakdown by Release Event Type**

Release Event	Percent of Total Costs Across All Trials
Undocumented Deep Well Leak	63.5%
CO <sub>2</sub> Injection Well Leak	7.4%
Rapid Leakage Through Confining Zone	0.2%
Slow Leakage Through Confining Zone	1.0%
Release Through Existing Faults	0.0%
Release Through Induced Faults	0.5%
Leakage Through Confining Zone/Faults then Shallow Well	27.4%

**Table 6. Cost Estimation Monte Carlo Trials with Identified Characteristics**

Category	Number of Trials	Percent of Total Trials
Total trials	50,000	100%
No costs incurred	42,243	84.5%
Costs < \$1 million	6,400	12.8%
Costs \$1-\$2 million	1,314	2.6%
Costs \$2-\$3 million	43	0.001%
Costs > \$3 million	0	0%
1 event occurring	7,093	14.2%
2 events occurring	631	1.3%
3 events occurring	32	0.001%
4 events occurring	1	0.00002%
5 or more events occurring	0	0%

# Composition of Stream

- Data: Feed gas test reports (recent as of Dec 2021)
- Process simulations will estimate final composition of stream, expect some contaminant dropout with the water

RESULT	PARAMETER, CHEMICAL FORMULA (UNITS)	DL	METHOD
99.8	Carbon Dioxide Purity (% v/v)	5.	ISBT 2.0
133	Total Hydrocarbons as Methane THC (ppm v/v as CH <sub>4</sub> )	0.1	ISBT 10.0
133	Total Non-Methane Hydrocarbons TNMHC (ppm v/v as CH <sub>4</sub> )	0.1	ISBT 10.1
0.6	Carbon Monoxide CO (ppm v/v)	0.5	ISBT 5.0
nd	Ammonia NH <sub>3</sub> (ppm v/v)	0.5	ISBT 6.0
nd	Oxides of Nitrogen NO <sub>x</sub> (ppm v/v)	0.5	ISBT 7.0
nd	Nitrogen Dioxide NO <sub>2</sub> (ppm v/v)	0.5	ISBT 7.1
nd	Nitric Oxide NO (ppm v/v)	0.5	ISBT 7.2
<b>Source Specific Parameters (ppm v/v)</b>			
sc	Hydrogen Cyanide HCN	0.5	ISBT 17.0
nd	Vinyl Chloride C <sub>2</sub> H <sub>3</sub> Cl	0.1	ISBT 18.0
sc	Phosphine PH <sub>3</sub>	0.1	ISBT 19.0
nd	Ethylene Oxide C <sub>2</sub> H <sub>4</sub> O	0.1	ISBT 20.0
<b>Non-Condensable Gases (NCG, ppm v/v)</b>			
760	Nitrogen N <sub>2</sub>	4.0	ISBT 4.0
220	Oxygen O <sub>2</sub>	4.0	ISBT 4.0
9	Argon Ar	4.0	ISBT 4.0
nd	Hydrogen H <sub>2</sub>	10.0	ISBT 4.0
nd	Helium He	10.0	ISBT 4.0
<b>Volatile Hydrocarbons (VHC, ppm v/v)</b>			
nd	Methane	0.5	ISBT 10.1
nd	Ethylene	0.5	ISBT 10.1
nd	Ethane	0.5	ISBT 10.1
nd	Propylene	0.5	ISBT 10.1
nd	Propane	0.5	ISBT 10.1
nd	Isobutane	0.5	ISBT 10.1
nd	n-Butane	0.5	ISBT 10.1
nd	Butenes	0.5	ISBT 10.1
nd	Isopentane	0.5	ISBT 10.1
nd	n-Pentane	0.5	ISBT 10.1
nd	Pentenes	0.5	ISBT 10.1
nd	C <sub>6</sub> +	0.5	ISBT 10.1

RESULT	Aromatic Hydrocarbons (BTEX, ppm v/v)	DL	METHOD
nd	Benzene AHC	0.002	ISBT 12.0
nd	Toluene	0.002	ISBT 12.0
nd	Ethyl Benzene	0.002	ISBT 12.0
nd	m+p Xylene	0.002	ISBT 12.0
nd	o-Xylene	0.002	ISBT 12.0
<b>Volatile Sulfur Compounds (VSC, ppm v/v)</b>			
0.20	Hydrogen Sulfide H <sub>2</sub> S	0.02	ISBT 14.0
0.06	Carbonyl Sulfide COS	0.02	ISBT 14.0
nd	Sulfur Dioxide SO <sub>2</sub>	0.02	ISBT 14.0
nd	Methyl Mercaptan	0.02	ISBT 14.0
nd	Ethyl Mercaptan	0.02	ISBT 14.0
0.33	Dimethyl Sulfide	0.02	ISBT 14.0
nd	Carbon Disulfide	0.02	ISBT 14.0
nd	i-Propyl Mercaptan	0.02	ISBT 14.0
nd	t-Butyl Mercaptan	0.02	ISBT 14.0
nd	n-Propyl Mercaptan	0.02	ISBT 14.0
nd	Methyl Ethyl Sulfide	0.02	ISBT 14.0
nd	sec-Butyl Mercaptan	0.02	ISBT 14.0
nd	i-Butyl Mercaptan	0.02	ISBT 14.0
nd	Diethyl Sulfide	0.02	ISBT 14.0
nd	n-Butyl Mercaptan	0.02	ISBT 14.0
nd	Dimethyl Disulfide	0.02	ISBT 14.0
nd	Diethyl Disulfide	0.02	ISBT 14.0
nd	Other Sulfurs	0.02	ISBT 14.0
0.59	Total Sulfur Content TSC as S	0.02	ISBT 13.0
<b>Volatile Oxygenates (VOX, ppm v/v)</b>			
1.0	Acetaldehyde AA	0.05	ISBT 11.0
nd	Ethylene Oxide	0.1	ISBT 20.0
nd	Dimethyl Ether	0.1	ISBT 11.0
nd	Methyl Ethyl Ether	0.2	ISBT 11.0
0.6	Methanol MeOH	0.2	ISBT 9.0
nd	Propionaldehyde	0.2	ISBT 11.0
0.5	Acetone	0.2	ISBT 11.0
81	Ethanol	0.2	ISBT 11.0
nd	Isopropanol	0.2	ISBT 11.0
20	Ethyl Acetate	0.2	ISBT 11.0
nd	t-Butanol	0.2	ISBT 11.0
nd	n-Propanol	0.2	ISBT 11.0
nd	2-Butanol	0.2	ISBT 11.0
1.6	Isobutanol	0.2	ISBT 11.0
3.0	n-Butanol	0.2	ISBT 11.0
5.8	Isoamyl Alcohol	0.2	ISBT 11.0
0.6	Isoamyl Acetate	0.2	ISBT 11.0

Figure 3. Feed Gas Composition

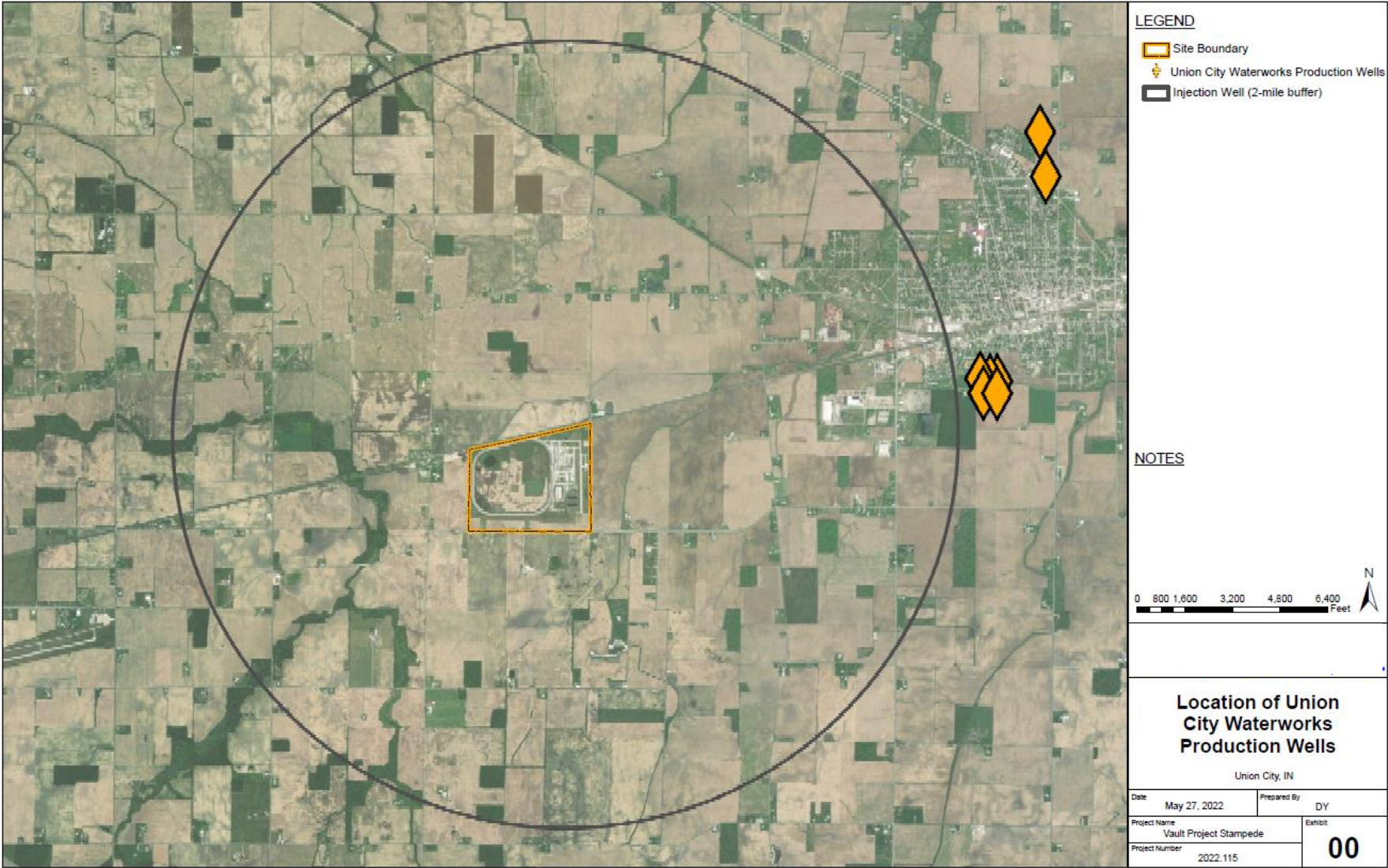


Figure 4. Union City Water Works Source Water Wells

## 6 Total Financial Assurance Cost

Based on the discussion provided in Sections 2 through 5 of this document, as well as the relevant third-party information and verified quotes, the following table was assembled to determine the total value of the financial assurance package.

**Table 7. Financial Assurance Cost Breakdown**

<b>Component of Financial Assurance</b>	<b>Amount of Funding</b>
Corrective Action	\$506,418
Injection Well Plugging and Abandonment	\$250,000
PISC and Site Closure	\$2,693,000
ERRP	\$2,679,000
<b>Total</b>	<b>\$6,128,418</b>

As displayed in Table 7, above, the total value proposed for the financial assurance package is \$6,128,409.

## 7 Method of Financial Assurance

As described in the Class VI Guidance documents, there are seven financial responsibility instruments:

1. Trust Fund
2. Standby Trust Letter of Credit
3. Surety Bond
4. Insurance
5. Financial Test and Corporate Guarantee
6. Escrow Account

After discussions with several insurance companies, OCP and Cardinal have decided to pursue the following methods to demonstrate financial responsibility:

- Corrective Action, Injection Well P&A, and the PISC and Site Closure will be covered by a surety bond to be posted by an insurance firm in an amount sufficient to fulfill the obligations laid out in Table 2.
- The ERRP portion of the financial assurance packer will be fulfilled by an insurance firm using an insurance policy sufficient to fulfill the obligation laid out in Table 2.

Each method of financial assurance will contain applicable protective conditions of coverage as required pursuant to 40 CFR 146.85(a)(4). The financial assurance will be maintained for the time period required in 40 CFR 146.85(b).

## **8 Reassessment of Financial Assurance**

The values detailed in Table 7 and this document will be reevaluated annually or as otherwise required by 40 CFR 146.85. As such, the insurance policy and values of the bonds for the remaining section will be reevaluated and updated annually. Any changes to the financial assurance will be communicated to the Director in accordance with 40 CFR 146.85(a)(5). Any adverse financial conditions that may affect the Operator's ability to carry out injection well plugging and post-injection site care and site closure will be communicated to the Director in accordance with 40 CFR 146.85(d).

## References

- (2022). *Attachment 1: Narrative*. Class VI Permit Application Narrative; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 10: ERRP*. Emergency And Remedial Response Plan; Hoosier#1 Project, Vault 44.01.
- (2022). *Attachment 11: QASP*. Project Hoosier#1, Vault 4401.
- (2022). *Attachment 2: AoR and Corrective Action*. Area Of Review And Corrective Action Plan; Project Stampede, Vault 4401.
- (2022). *Attachment 3: Financial Responsibility*. Financial Responsibility; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 4: Well Construction*. Injection Well Construction Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 5: Pre-Op Testing Program*. Pre-Operational Formation Testing Program; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 6: Well Operations*. Well Operation Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 7: Testing And Monitoring*. Testing And Monitoring Plan; Project Hoosier#1, Vault 4401.
- (2022). *Attachment 8: Well Plugging*. Project Hoosier#1, Vault 4401.
- (2022). *Attachment 9: Post-Injection Site Care*. Post-Injection Site Care And Site Closure Plan; Project Hoosier#1, Vault 4401.
- FutureGen. (2007, April). *Final Risk Assessment Report for the FutureGen Environmental Impact Statement*. Retrieved from Department of Energy: <https://www.energy.gov/sites/prod/files/EIS-0394-DEIS-RiskAssessmentReport-2007.pdf>
- Indiana Department of Environmental Management. (2022). *Maximum Contaminant Levels for Drinking Water*. Retrieved from IN.gov: <https://www.in.gov/idem/cleanwater/drinking-water/drinking-water-compliance-section/water-systems/maximum-contaminant-levels-for-drinking-water/>
- Raimi, D. A.-S. (2021). Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimate and Cost Driven Drivers. *Environmental Science Technology*.
- Stats Indiana. (2020). *Indiana City/Town Census Counts, 1900 to 2020*. Retrieved from Stats Indiana: [http://www.stats.indiana.edu/population/poptotals/historic\\_counts\\_cities.asp](http://www.stats.indiana.edu/population/poptotals/historic_counts_cities.asp)

Plan revision number: 1.0  
Plan revision date: July 4, 2022

The City of Union City, Indiana. (2022). *Misc. Info Page*. Retrieved from Union City, Indiana:  
<https://unioncity-in.com/misc-fact-pages#bf19eb4a-2f2e-4e41-a38d-fc8e7a3b12c5>

United States Environmental Protection Agency. (2022, February 17). *Secondary Drinking Water Standards: Guidance for Nuisance Chemicals*. Retrieved from EPA.com:  
<https://www.epa.gov/sdwa/secondary-drinking-water-standards-guidance-nuisance-chemicals>

## Class VI UIC Financial Responsibility Demonstration

This submission is for:

Project ID: R05-IN-0003

Project Name: Project Hoosier #1

Current Project Phase: Pre-Injection Prior to Construction

### Cost Estimates

Company providing estimates: Explor, Michigan Wireline, Subsurface Dynamics, Industrial Economics, Franklin Well Services

Cost of each phase: Date of Third-Party Estimate:

Corrective Action on Deficient Wells: \$506,418.00 6/23/2022

Plugging Injection Well: \$250,000.00 4/20/2022

Post-Injection Site Care and Site Closure: \$2,693,000.00 5/24/2022

Emergency and Remedial Response: \$2,679,000.00 5/30/2022

Total Cost Estimate: \$6,128,418.00

Year of Dollars: 2022

Cost Estimate File: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/FinancialResp-07-07-2022-1529/For--Submittal.zip](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/FinancialResp-07-07-2022-1529/For--Submittal.zip)

Additional Cost Information: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/FinancialResp-07-07-2022-1529/NA.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/FinancialResp-07-07-2022-1529/NA.pdf)

Description of Information Submitted: Submission contains third party quotes and package write up for submittal

### Trust Fund

Number of Trust Fund Instruments: 0

### Surety Bond

Number of Surety Bond Instruments: 0

### Letter of Credit

Number of Letter of Credit Instruments: 0

### Third Party Insurance

Number of Third Party Insurance Instruments: 0

### Escrow Account

Number of Escrow Account Instruments: 0

### Self Insurance

Is Self Insurance Used as a Financial Instrument: No

### Other Instrument

Number of Other Instruments: 0

### Notifications

### Complete Submission

Authorized submission made by: Ricky Weimer

Comments regarding this submission: Financial assurance instruments have been selected for each item, but have not yet been formally established. These will be established at a later date, after well installation and before final permits are provided.

For confirmation a read-only copy of your submission will be emailed to: [craig@vault4401.com](mailto:craig@vault4401.com)

**PLUGGING AND ABANDONMENT AFE**

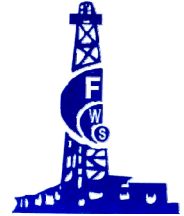
INJECTION WELL					CCS1		AFE #		
					<b>TBD</b>				
VAULT4401		TYPE CODE AND DESCRIPTION			PROPERTY NUMBER NA		AREA NA		
REQUEST DATE		SCHEDULED START DATE TBD		SCHEDULED COMPLETION DATE TBD		PROGRAM YEAR TBD		PROJECTED TOTAL DEPTH <b>TBD</b>	
STATE IN		COUNTY Randolph		LEGAL DESCRIPTION 40.186587°, -84.864284°			PRIME OBJECTIVE		
JOA NUMBER		LAND LEASE NUMBER NA		REGION NA		BRANCH NA		DISTRICT NA PROJECT Hoosier #1	
BOOKED PUD RESERVES					PREPARED BY & DATE Randy Evans 05-23-22		TITLE APPROVAL/PLAT DATE		
DESCRIPTION OF PROPOSAL OR REASON FOR SUPPLEMENT Plugging and Abandonment of Injection Well									
<b>x</b> ORIGINAL AFE					<b>GROSS WORKING INTEREST COST DETAIL (\$)</b>				
REVISED / SUPPLEMENTAL AFE					<b>ORIGINAL ESTIMATE</b>		<b>REVISED ESTIMATE</b>		
<b>ACCOUNT</b>		<b>COST CATEGORIES</b>			<b>DRY HOLE</b>	<b>COMPLETED HOLE</b>	<b>Incremental Costs</b>	<b>REVISED TOTAL</b>	
<b>INTANGIBLES</b>	Land Services, (Surveying, Title Opinion, Permitting, Damages, ROW's)								\$0
	Location Construction (Labor, stone, culverts, fabric, filter, fence, cellar)								\$0
	Mobilization / Demobilization (Moving drilling unit to/from drill site)								\$0
	Contract Drilling: Turnkey FT @								\$0
	Contract Drilling: Footage FT @								\$0
	Contract Drilling: Day work 6 Days @ \$ 10,000.00					\$60,000			\$60,000
	Directional Drilling Services Days @								\$0
	Bits								\$0
	Power, Fuel & Water (for drilling operations only)								\$0
	Operations recording (Pason / Totco)								\$0
	Drilling Mud & Chemicals								\$0
	Mud Logging Services 0 Days @ \$ 2,400.00								\$0
	Drill pipe rental/repair (heavy weight & DC) & post job inspection								\$0
	Equipment Rental : foam air; BOP's, slips, elevators, subs								\$0
	Well Supplies (Centralizers, Float Equip., DV Tools, Baffles, etc.)								\$0
	Cementing					\$116,300			\$116,300
	Logging (Openhole Logs) Gyro / Orientation								\$0
	(Casedhole Logs) CBL Log / Perforating								\$0
	Stimulation - Acidizing & Fracturing (inc.: tank rental & water hauling)								\$0
	Completion Unit (Service Rig, etc.)								\$0
	Solids disposal								\$0
	Fluid Disposal (Drilling & Completion Fluids)								\$0
	Locations Restoration / Reclamation/ dozer rental					\$10,000			\$10,000
	Supervision 6 Days @ \$ 1,800.00					\$10,800			\$10,800
	Transportation								\$0
	Contract Labor (includes roustabout services, welders, power tongs)								\$0
	Drilling Overhead								\$0
	Miscellaneous Contingency					\$17,900			\$17,900
	Injection testing								\$0
	DST(s)								\$0
Coring & analysis								\$0	
Rentals forklift, light plants, office 6 Days @ \$ 5,000.00					\$30,000			\$30,000	
Centrifuge& cuttings equipment 0 Days @ \$ 5,000.00								\$0	
Fluid storage tank rentals. 6 tanks 2200 each								\$0	
Trucking/delivery					\$5,000			\$5,000	
Safety personell								\$0	
Well head & equipment								\$0	
Engineering Support 0 Days @ \$ 1,800.00					\$0			\$0	
<b>GROSS INTANGIBLE COSTS</b>					<b>\$0</b>	<b>\$250,000</b>	<b>\$0</b>	<b>\$250,000</b>	
<b>TANGIBLES</b>	Tubing 3-1/2" 9.3# L80 lined FT @					\$ -			
	Casing Conductor 20" 94# J55 STC FT @					\$ -			
	13-3/8" 54.5# J55 STC FT @					\$ -			
	9-5/8" 36# J55 STC FT @					\$ -			
	7" 26# L80 LTC FT @					\$ -			
	7" 26# 13Gr80 Special FT @					\$ -			
	Well Equipment: -Surface								
	-Subsurface								
	Lease Equipment: -Artificial Lift								
	-Flow Lines / Gathering Lines								
	-Tank Batteries & Separators								
	-Electric Systems & Transmission Lines								
	-Other Production Equipment								
	<b>GROSS TANGIBLE COSTS</b>					<b>\$ -</b>	<b>\$ -</b>		
	<b>GROSS TOTAL COSTS</b>					<b>\$ -</b>	<b>\$ 250,000.00</b>		
<b>NET INTANGIBLE COSTS</b>									
<b>NET TANGIBLE COSTS</b>									
<b>NET TOTAL COSTS</b>									

PARTICIPATION			COMPANY AND NON OPERATOR APPROVAL	
COMPANY:	BCP%	ACP%	NAME:	DATE
<b>TOTAL</b>	<b>0%</b>	<b>0%</b>		



PO Box 237, 400 Main Street  
Vincennes, IN 47591  
Phone: (812) 494-2800  
FAX: (812) 494-2508



To: Mr. Randy Evans  
Subject: Cardinal CCS #1  
For: Cementing estimate to PTA  
Date: April 20, 2022

Mr. Evans,

I am pleased to present this cost estimate & proposal to plug the Cardinal CCS #1 project you are planning. Upon learning any new details, we can adjust this proposal accordingly. Due to the cost of fuel and current supply chain issues, I am providing this cost estimate at list cost. Once there is a date set for this project to begin, we can revisit this cost estimate and discuss any discounts that we can apply. We will also need to discuss the EVERCRETE cement and coordinate with SLB. In the end it may be best to utilize SLB's pumping services for pumping the EVERCRETE. We can contract them if needed.

**Plug 7" 26# casing in 7 intervals from 3,600' – 0' with the following:**

**Day #1**

Plug #1 3,600' – 3,100' with 100 sx of EVERCRETE  
Plug #2 3,100' – 2,600' with 100 sx of EVERCRETE  
Plug #3 2,600' – 2,100' with 100 sx of EVERCRETE

**Day #2**

Plug #4 2,100' – 1,600' with 95 sx of Type 1 Neat  
Plug #5 1,600' – 1,100' with 95 sx of Type 1 Neat  
Plug #6 1,100' – 600' with 95 sx of Type 1 Neat  
Plug #7 600' – 0' with 110 sx of Type 1 Neat

Top off as needed (50 sx of Type 1 Neat included in estimate for top off)

**Included in this PTA cost estimate:**

1 - Supervisor  
5 - Equipment operators  
230 - Mileage on cement pump  
460 - Mileage on cement bulk truck (2 trucks)  
500 - Mileage on cement bulk truck (1 truck to pick up EVERCRETE in Ohio)  
230 - Mileage on 1 pickup to location  
500 - Mileage on 1 pickup to Strasburg, Ohio for EVERCRETE pickup  
24 - Hours on location  
20 - Subsistence (6 men for 3 nights & 2 men for 1 to pick up EVERCRETE)  
1 - Cement pump  
3 - Cement bulk trucks  
41,830 - Pounds of cement blended and loaded  
445 - Sacks of Type 1 cement  
300 - Sacks of EVERCRETE  
5 - Gallons of defoamer  
2 - Gallon of Biocide

**Cost estimate: \$116,254.75**

Cement slurry information:

Type 1 Neat

Density: 15.6 ppg  
Yield: 1.18 ft<sup>3</sup>/sack  
Mix water: 5.2 gal/sack

EVERCRETE

Density: 16.05 ppg  
Yield: 1.09 ft<sup>3</sup>/sack  
Mix water: 3.37 gal/sack

Please advise on any changes or adjustments you would like to see within this proposal. If there are any questions, feel free to call at any time. I would like to thank you for allowing Franklin Well Services the opportunity to give you this price estimate. We appreciate your interest in our services.

Sincerely,

Jonathan Gatten  
Technical Sales  
(270) 748-6419

MICHIGAN WIRELINE SERVICES INC

PO BOX 782

MT PLEASANT, MI 48804-0782

# Estimate

Date	Estimate No.
4/27/2022	220

Name/Address

RICKY WEIMER  
EASTERN INDIANA

		Project	
Description	Qty	Rate	Total
RAT/TEMP LOGS IN EASTERN INDIANA - WELL #3 - 1400'	3		
WIRELINE/MAST TRUCK		3,200.00	3,200.00
PRESSURE CONTROL HIGH PRESSURE		1,200.00	1,200.00
MILEAGE CHARGE. - WIRELINE TRK - ESTIMATED 550 MILES ROUND TRIP - SPLIT BETWEEN THREE WELLS		505.00	505.00
SUBSISTENCE - 3 CREW MEMBERS - 1 NIGHT R.A. MATERIAL.		250.00	750.00
RADIOACTIVE TRACER DEPTH CHARGE MIN CHARGE		1,000.00	1,000.00
RADIOACTIVE TRACER OPERATING CHARGE. MIN CHARGE		1,500.00	1,500.00
TEMPERATURE LOG DEPTH CHARGE. - MIN CHARGE		1,020.00	1,020.00
TEMPERATURE LOG DEPTH CHARGE. - MIN CHARGE		720.00	720.00
TEMPERATURE LOG OPERATING CHARGE. - MIN CHARGE		825.00	825.00
Total			\$10,720.00

MICHIGAN WIRELINE SERVICES INC

PO BOX 782

MT PLEASANT, MI 48804-0782

# Estimate

Date	Estimate No.
4/27/2022	219

Name/Address

RICKY WEIMER  
EASTERN INDIANA

		Project	
Description	Qty	Rate	Total
RAT/TEMP LOGS IN EASTERN INDIANA - WELL #2 - 3200'			
WIRELINE/MAST TRUCK		3,200.00	3,200.00
PRESSURE CONTROL HIGH PRESSURE		1,200.00	1,200.00
MILEAGE CHARGE. - WIRELINE TRK - ESTIMATED 550 MILES ROUND TRIP - SPLIT BETWEEN THREE WELLS		505.00	505.00
SUBSISTENCE - 3 CREW MEMBERS - 2 NIGHTS R.A. MATERIAL.	6	250.00	1,500.00
RADIOACTIVE TRACER DEPTH CHARGE		1,000.00	1,000.00
RADIOACTIVE TRACER OPERATING CHARGE.	3,200	0.70	2,240.00
TEMPERATURE LOG DEPTH CHARGE.	1,500	0.68	1,020.00
TEMPERATURE LOG OPERATING CHARGE. -	3,200	0.36	1,152.00
SURFACE TO 3200'	3,200	0.55	1,760.00
		Total	\$13,577.00

MICHIGAN WIRELINE SERVICES INC

PO BOX 782

MT PLEASANT, MI 48804-0782

# Estimate

Date	Estimate No.
4/27/2022	218

Name/Address

RICKY WEIMER  
EASTERN INDIANA

		Project	
Description	Qty	Rate	Total
RAT/TEMP LOGS IN EASTERN INDIANA - WELL #1 - 3200'			
WIRELINE/MAST TRUCK		3,200.00	3,200.00
PRESSURE CONTROL HIGH PRESSURE		1,200.00	1,200.00
MILEAGE CHARGE. - WIRELINE TRK - ESTIMATED 550 MILES ROUND TRIP - SPLIT BETWEEN THREE WELLS		505.00	505.00
SUBSISTENCE - 3 CREW MEMBERS - 2 NIGHTS R.A. MATERIAL.	6	250.00	1,500.00
RADIOACTIVE TRACER DEPTH CHARGE		1,000.00	1,000.00
RADIOACTIVE TRACER OPERATING CHARGE.	3,200	0.70	2,240.00
TEMPERATURE LOG DEPTH CHARGE.	1,500	0.68	1,020.00
TEMPERATURE LOG OPERATING CHARGE. - SURFACE TO 3200'	3,200	0.36	1,152.00
	3,200	0.55	1,760.00
		Total	\$13,577.00

## Ricky Weimer

---

**From:** Richard Gray  
**Sent:** Tuesday, May 24, 2022 9:22 AM  
**To:** Preston Evans; Ricky Weimer  
**Subject:** FW: 2D in Indiana?

Preston – figured you had been on some of the comms but not all for 2D in Indiana.

Ricky – bottom of this is Explor rough estimate for 3D. I'd be happy to reach out to a few more folks to verify – I was talking to SAE last week who told me the majority of their work is now CCS in the USA.

---

**From:** Allan Châtenay <al@explor.net>  
**Sent:** May 12, 2022 12:24 PM  
**To:** Richard Gray <richard@vault4401.com>  
**Subject:** RE: 2D in Indiana?

Rik;

Great to hear from you! Congratulations on landing the part time gig!

Indeed, we are staying busy with projects in Oklahoma and Montana that immediately followed our Illinois 3D success. We are permitting a substantial Michigan project and are currently in Montana on a couple of high density 3D projects.

After this project wraps up late next week we will be mobilizing to a 2D in Illinois that will take us most of June to finish, so moving to a 2D in Indiana in July would be near-perfect with very low mobilization costs. As an example, a 20' RI and an 80' SI with vibroseis (all live 2D lines assuming 6-7 miles long), we will be around \$4,500/mi (fixed, no surprises turnkey) including mob/demob, IntelliSeis planning, positioning, nav and real time monitoring, receiver deployment and retrieval, vibroseis source acquisition, (and likely also some technology testing and development). If you would like a formal proposal, please send along the desired parameters, shape files, etc. and we can send you a proposal. If you want to go with a weight drop (or the new source we are developing), that price would come down.

A note that after seeing us in action and comparing our performance to other contractors they have used, our US clients now simply direct-award the projects to us. We have achieved a step-change in efficiency, dramatically reducing HSE exposure – the most fundamental action that can be taken to reduce HSE risk. (Just posted the stats on LinkedIn).

On the 3D side of things, with the experience in Illinois and Montana under our belts, we can offer the following new pricing model for vibroseis HD3D in support of CCUS in benign, open terrain:

- 300' RLI, 30' RI
- 300' SLI, 30' SI
- All-inclusive seismic data acquisition cost <USD\$70K/mi<sup>2</sup> (4 sq mi minimum)
  - Excludes permitting and processing.
  - Permit agent at USD\$700-\$850/day depending on specific circumstance

I think I had been closer to \$100K/sq. mi. before...we now know we can do significantly better...if you have some projects for us to look at, send them our way and we can dial in costs a bit better.

Thx,

Al.

---

**From:** Richard Gray <[richard@vault4401.com](mailto:richard@vault4401.com)>  
**Sent:** May 12, 2022 10:42 AM  
**To:** Allan Châtenay <[al@explor.net](mailto:al@explor.net)>  
**Subject:** 2D in Indiana?

Hi Al

I hope you are doing well and keeping busy. As you can see from the email address I'm doing a little bit of parttime work helping out Marcia and Scott with large scale project definition and planning. Scott mentioned you had called but he has been flat out with numerous high priority items so has been pushing off anything that's not currently on fire.

One item that wasn't on fire until this week was some 2D needed in Indiana (Montgomery County) in July timeframe. It is only approx. 20miles (3 or 4 lines) and is in Jack Racers backyard. But given that you had so much fun in the states last summer I wondered if you would be interested in a few more details and providing an estimate? For a small 2D its fully understandable if you say not now.

As for 3Ds for Vault – I'm working with the other project managers to define timing on potentially 3 or 4 different projects and fighting hard for them all to be high density (similar size and effort to what I think you did for ISGS) Timing unclear. When you get a chance it would be good to get together to see what went well, what you would do different and get your thoughts on a good number to use in estimating. (numbers you provided to Marcia last year have been carried into quite a few estimates).

Talk to you soon  
Rik



**Richard Gray, P.Geo.**

**Project manager/Geophysical Consultant**

C: 403-473-0905

E: [richard@vault4401.com](mailto:richard@vault4401.com)

W: [www.vault4401.com](http://www.vault4401.com)

**Subsurface Dynamics Inc.**  
545, 940 6<sup>th</sup> Avenue SW  
Calgary, Alberta, T2P 3T1



June 23, 2022

Vault 44.01 Ltd.  
ATTN: Ricky Weimer, Project Manager  
email: Ricky@vault4401.com

Calgary, Alberta

Dear Ricky,

**Subject: Cardinal Class VI Permit AoR Reevaluation Project**

Thank you for considering Subsurface Dynamics Inc. for this engagement.

The Scope of Work presented in this proposal is based on a request from Vault 44.01 Ltd. to perform Cardinal Class VI Permit AoR Reevaluation project.

Subsurface Dynamics Inc. is a Calgary-based, privately held Engineering firm with extensive expertise in the oil and gas, CCS and green energy industries. With an experienced staff and access to state of the art software solutions (Petrel, CMG, Gohfer 3D, IHS) coupled with proprietary technology development solutions (AETHEN.IO), we are well positioned to provide you with an industry leading product.

We appreciate the opportunity to submit this proposal, **which is valid for thirty (30) days from the above date**, and trust that it provides all the information you require. If you have any questions relating to the proposal, or any of the services provided by us, please do not hesitate to contact me.

Yours sincerely,

Dmitry Deryushkin  
Director, Technology

Encl.- 1. Proposal



**Cardinal Class VI Permit AoR Reevaluation  
Project  
V3 Proposal**

**Prepared for:  
Vault 44.01 Ltd.**

**Prepared by:  
Subsurface Dynamics Inc.  
545, 940 6th Avenue SW  
Calgary, Alberta, T2P 3T1**

**June 17, 2022**



































## **Class VI UIC Pre-Operational Testing**

This submission is for:

Project ID: R05-IN-0003

Project Name: Project Hoosier #1

Current Project Phase: Pre-Injection Prior to Construction

Proposed Pre-Operational Testing: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/PreOpTest-07-07-2022-1125/5.--Pre-Operational--Testing--Program\\_Hoosier--1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/PreOpTest-07-07-2022-1125/5.--Pre-Operational--Testing--Program_Hoosier--1.pdf)

Proposed Pre-Operational Testing Schedule: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/PreOpTest-07-07-2022-1125/Tentative\\_pre-op\\_testing\\_schedule.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/PreOpTest-07-07-2022-1125/Tentative_pre-op_testing_schedule.pdf)

State Pre-Operational Test Results: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/PreOpTest-07-07-2022-1125/NA.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/PreOpTest-07-07-2022-1125/NA.pdf)

## **Well and Cement Logs**

### **MITs**

### **Core Analyses**

### **Formation Characterization**

### **Injection Well Testing**

### **Complete Submission**

Authorized submission made by: Ricky Weimer

For confirmation a read-only copy of your submission will be emailed to: [craig@vault4401.com](mailto:craig@vault4401.com)

**ATTACHMENT 5: PRE-OPERATIONAL FORMATION TESTING PROGRAM**  
**40 CFR 146.82(a)(8), 146.87**

**HOOSIER #1 PROJECT**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
Cardinal Ethanol

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CO<sub>2</sub> Injection Well Location for Cardinal CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

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## **List of Acronyms**

ACZ	Above Confining Zone
APT	Annular Pressure Test
BGS	Below Ground Surface
BHA	Bottomhole Assembly
CBL-VDL	Cement Bond Log-Variable Density Log
DST	Drill Stem Test
ECS	Elemental Capture Spectroscopy
EPA	Environmental Protection Agency
FOT	Fall-off Test
MIT	Mechanical Integrity Test
MWD	Measurement While Drilling
NMR	Nuclear Magnetic Resonance
OAL	Oxygen Activation Logging
PVC	Polyvinyl Chloride
RAT	Radioactive Tracer Logging
SRT	Step-rate Testing
TD	Total Depth
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USDW1	Lowermost USDW Monitoring Well
ZVSP	Zero Offset Vertical Seismic Profile

## 1 Introduction

This document serves to detail the proposed Pre-Operational Formation Testing Program to be implemented to characterize the chemical and physical features of the lithology at Project Hoosier #1. The formations of note include, but are not limited to, the following:

- Mt. Simon Sandstone (injection zone),
- Eau Claire Formation (confining zone),
- Maquoketa Formation (which includes the lowest underground source of drinking water [USDW]), and
- Above confining zone (ACZ) intervals.

The Pre-Operational Testing Program laid out in this document is designed to meet the testing requirements of Title 40 of the U.S. Code of Federal Regulations Section 146.87 (40 CFR 146.87) and well construction requirements of 40 CFR 146.86. It includes a combination of logging, coring, fluid sampling, and formation hydrogeologic testing that will be completed during the drilling of the:

- USDW1: Deepest USDW monitoring well
- CCS1: CO<sub>2</sub> injection well,
- OBS1: Injection zone monitoring well
- ACZ1: Above confining zone monitoring well

Should the necessary data fail to be collected in the first three wells, the ACZ1 well will be used to collect missing overburden data. As a result of the scarcity of well data below the Trenton Formation, the final ACZ monitoring interval will be determined after the first deep well has been drilled for the project. Based on regional knowledge, it is expected that a suitable monitoring interval will be found at or immediately above the Knox Formation unconformity due to the Glenwood Formation's properties that create an effective barrier to fluid migration as observed to the east in Ohio.

Current plans are to drill the CCS1 in September 2023, pending receipt of an initial project permit. Following the drilling, completion, and testing of the well, a permit modification will be submitted to provide updated information regarding the results of the testing program.

The Pre-Operational Testing Program will determine and verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the injection zone, confining zone, and other relevant geologic formations (Figure 1 and Figure 2) via petrophysical logging and analysis, and coring. In addition, formation fluid characteristics will be obtained from the injection zone, USDW, ACZs to establish accurate baseline data against which future measurements may be compared after the start of injection operations.

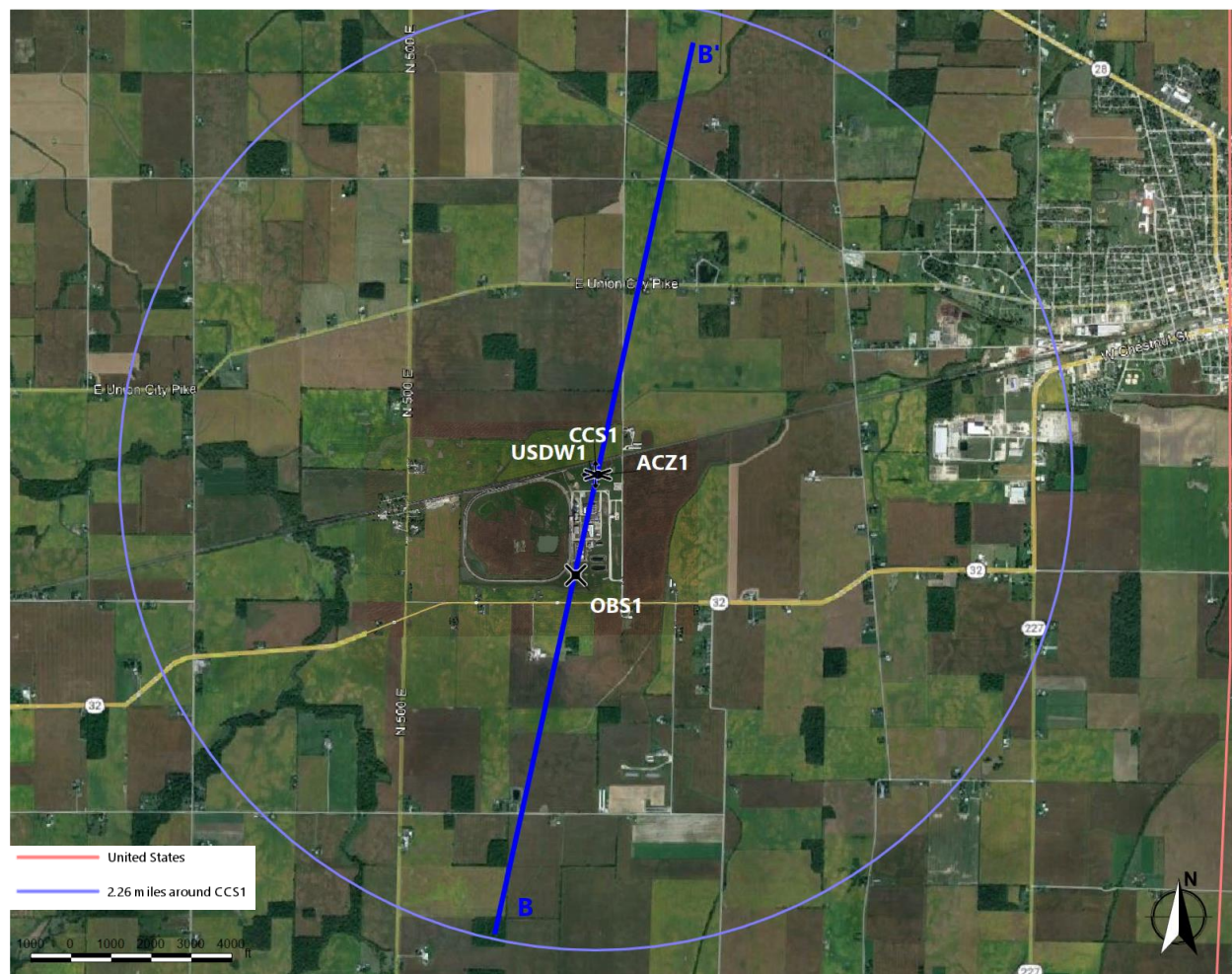
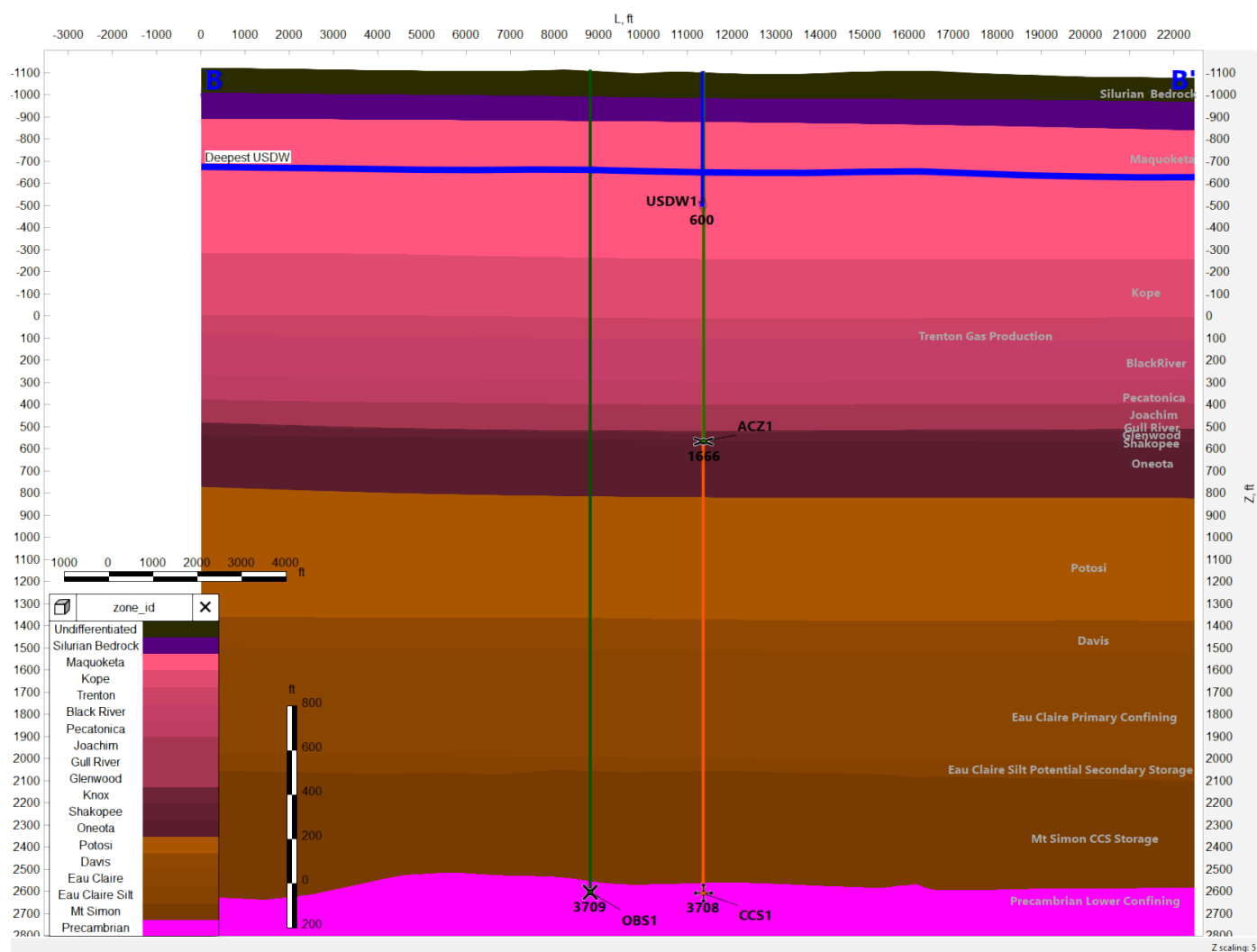


Figure 1: Site map of Cardinal wells



## **2 USDW1 Well Hydrogeologic Characteristics (146.87 (e))**

Before the drilling of CCS1, USDW1 will be drilled with a water well rig. This well and the associated data will be used to complete the following objectives:

- USDW1 will be drilled to confirm the depth of the deepest USDW at approximately 450 feet (ft) below ground surface (BGS) based on local well data (Attachment 1: Narrative, 2022). A USDW is defined by the EPA as an aquifer with less than 10,000 mg/L total dissolved solids (TDS).
- If an aquifer is not encountered before the anticipated 450 ft BGS, drilling will continue until an aquifer is encountered (Figure 2). The estimated total depth (TD) of this well is not expected to exceed 600 ft.
- USDW1 will be completed with polyvinyl chloride (PVC) casing and PVC screen across the deepest aquifer.
- Water samples will be collected to characterize the water quality. The primary goal is to identify groundwater with less than 10,000 mg/L TDS to establish the lowermost USDW for the project. This depth will serve to provide a depth to set surface casing for CCS1 and OBS1.

### **3 CCS1 Injection and OBS1 Observation Well Pre-Operational Formation Testing Program (146.87 (a))**

CCS1 will serve as the CO<sub>2</sub> injection well and OBS1 will serve as the deep monitoring well. As such, a rigorous Pre-Operational Testing Program will be performed to:

- Collect important site characterization data such as, but not limited to, wireline logs, core, and fluid samples,
- Ensure the well will not serve as an upward conduit for CO<sub>2</sub> migration to the overlying USDWs.

The well construction plan is presented in (Attachment 4: Well Construction, 2022). This section describes the Pre-Operational Testing Program that will be completed during the drilling and completion of CCS1. Should OBS1 be drilled prior to CCS1, similar methodologies will be used to collect data for characterization. The second well will present an additional opportunity to collect data should the following occur:

- The project is unable to collect a particular dataset in the first well,
- A dataset is collected but is not useable. (i.e., damaged core).

It has not currently been determined whether OBS1 will be drilled before, or after CCS1. Clarity as to the order of operations will be provided once a more detailed installation procedure is finalized.

#### **3.1 Deviation Surveys (146.87 (a)(1))**

Deviation surveys will be obtained as Cardinal CCS1 and OBS1 are drilled to determine the wellbore path from the surface to the total depth of the wells. It is currently planned that this will be done by running a survey tool in on wireline to measure the inclination. The tool has an electronic timer that is set at the surface to allow enough time to run the tool in the drill pipe to the desired depth. Following the set time, the tool is removed from the well. The result of the survey will then be reviewed prior to continuation of drilling

An alternative way to measure these deviation surveys is done by placing a measurement while drilling (MWD) tool, used to take well path surveys, on the bottomhole assembly (BHA) just above the drill bit. This tool records the inclination (deviation) and azimuth (direction), and then transmits this information to surface in real-time.

Hole deviation will be maintained at less than five degrees, as the planned maximum allowable deviation in the well is 5 degrees. If necessary, the wellbore will be steered back to acceptable deviation with directional tools, with a downhole motor or rotary steerable system added to the BHA. Surveys will be taken at the frequency shown in Table 1. In general, a survey will be performed every 300 ft during the drilling of the borehole unless deviation of the borehole becomes apparent.

Should the deviation increase, more frequent surveys will be performed, and remedial actions will occur as necessary to bring the well within specification. More frequent surveys will also be performed while drilling through zones that are likely to cause the bit to “walk” creating a greater risk for deviation.

**Table 1: CCS1 and OBS1 Deviation survey frequencies to be taken.**

Range of Deviation	Frequency of Survey
<1 degree	1 survey per every 300 ft. of hole
>1 degree, but < 2 degrees	1 survey per every 240 ft. of hole
>2 degrees, but < 3 degrees	1 survey per every 120 ft. of hole
>3 degrees, but < 4 degrees	1 survey per every 90 ft. of hole
>4 degrees, but <5 degrees	1 survey per every 30 ft. of hole

### 3.2 Well Logging: Before and After Surface Casing (146.87 (a)(2))

Table 2 summarizes the open and cased hole well logs that will be acquired before for the surface casing section of the well. The bottom of the surface casing is estimated to be between approximately 450 to 560 ft BGS.

**Table 2: CCS1 and OBS1 summary of wireline logs and associated parameters of logging tools to be run before and after surface casing is set (surface to between 450– 560 ft).**

Open/ Cased Hole	Log Type	Parameters Obtained	CCS1	OBS1
Open Hole (Required)	Gamma Ray	Lithology	X	
	Spontaneous Potential	Permeability	X	
	Resistivity	Fluid saturation, permeability	X	
	Caliper	Borehole diameter, stress	X	
<b>Surface Casing Will Be Installed and Cemented</b>				
Cased Hole (Required)	CBL – with radial arms	Surface casing cement integrity, external mechanical integrity	X	X
	Temperature	Temperature, external mechanical integrity	X	X
Cased Hole (Optional)	Ultrasonic Cement Evaluation	Cement integrity, external mechanical integrity	X	X

### 3.3 Well Logging: Deep Section (146.87 (a)(2))

Table 3 and Figure 3 summarize the well logs that will be run before and after long string casing is set and the purpose of each well log. The cased hole well logs will be acquired after the well is cemented and completed (Table 3). The well logs that are acquired to characterize the injection zone and confining zone will be run in the first deep well drilled for the project. A minimal logging suite will be acquired in the second deep well to correlate to the data acquired in the first well.

In addition to the well logs listed in Table 3, the project may run other specialty well logs over the injection zone and confining interval in order to further characterize these formations. Specialty logs may include, but are not limited to, elemental capture spectroscopy

(ECS), nuclear magnetic resonance (NMR), dipole sonic in multiple modes, or zero offset vertical seismic profiles (ZVSP).

**Table 3: CCS1 and OBS1 summary of wireline logs and associated parameters of logging tools to be run before and after long string casing (surface to TD).**

Log	Log Type	Parameters Obtained	CCS1	OBS1
Open Hole Logging (Required)	Gamma Ray	Lithology	X	
	Density	Porosity, density	X	
	Neutron Porosity	Porosity	X	
	Spontaneous Potential	Permeability	X	
	Resistivity	Fluid saturation, permeability	X	
	Caliper	Borehole diameter, stress	X	
	Image Log	Lithology, porosity, borehole diameter, fracture characterization, stress	X	
Special Open Hole Logging (Optional)	Sonic Log	Porosity, formation velocities	X	
<b>Long string casing will be installed and cemented</b>				
Cased Hole Logging (Required)	CBL with radial arms	Cement integrity, external mechanical integrity	X	X
	Temperature	Temperature, external mechanical integrity	X	X
Cased Hole Logging (Optional)	Ultrasonic Cement Evaluation	Cement integrity, external mechanical integrity	X	X
	Pulsed Neutron	Lithology, baseline fluid saturation, porosity	X	X

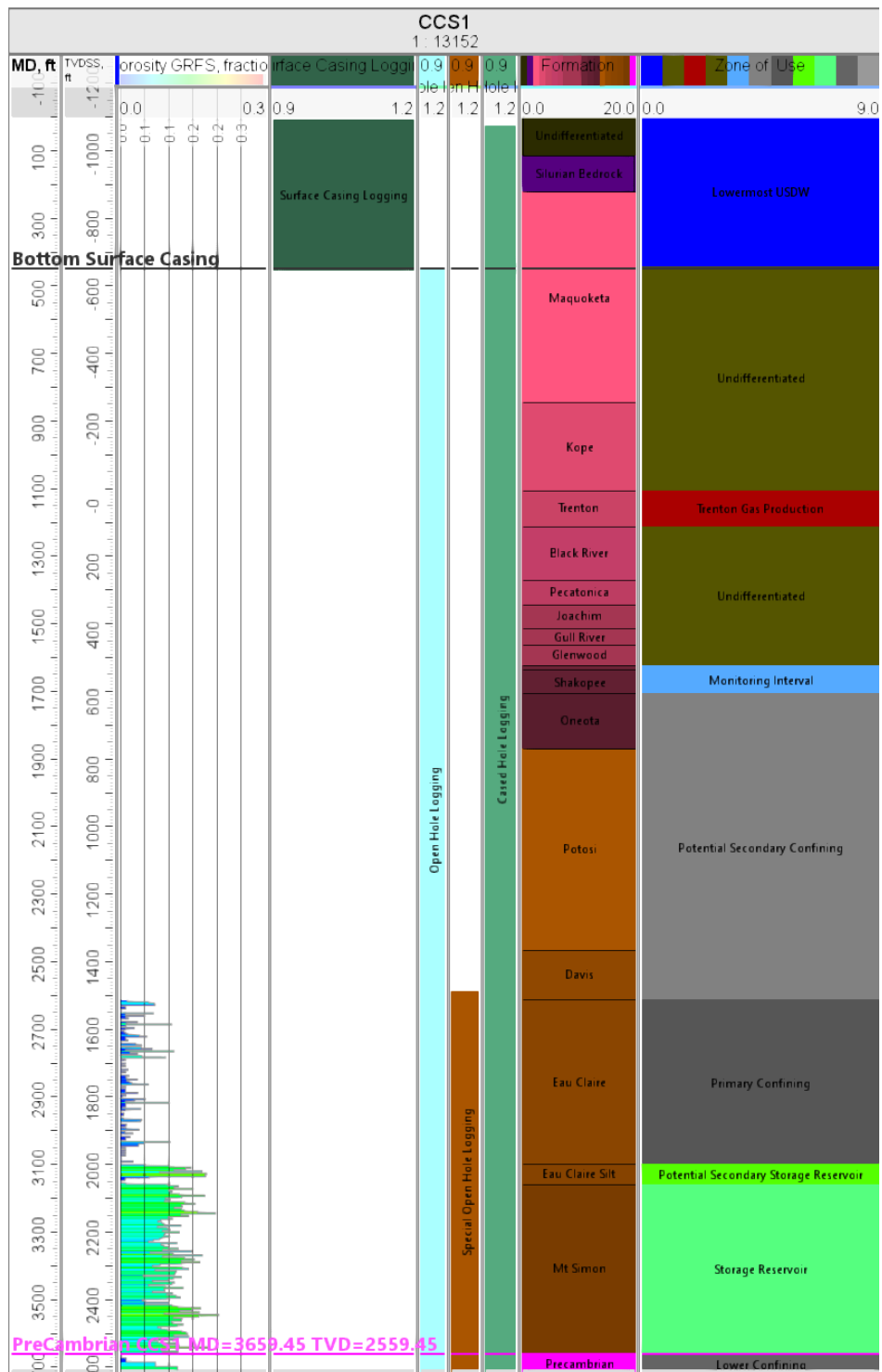


Figure 3: CCS1 Summary of wireline logs and associated parameters of logging tools to be run before and after surface casing (surface to TD).

### 3.4 CCS1 and OBS1 Injection Well Core Program (146.87 (b)(d))

Once the first deep well for the project has been drilled, the well logs will be analyzed and used to pick the optimal intervals to obtain core from the confining zone and the injection zone in the second well drilled for the project (Figure 4). Approximately 50 ft of core will be acquired in both the Eau Claire Shale and the Mt. Simon Sandstone. Figure 4 and Table 5 summarize the plans for whole core acquisition and testing from the second deep well.

**Table 4: Whole core collection plan. Whole core plugs will be taken from the whole core at regular intervals. Sidewall core collection will be contingent on the results of the well logging and the success of the whole core acquisition.**

Core Type	Target Interval MD (ft)	Formation	Core Size
Whole Core	2,675 – 2,725	Eau Claire Shale	4 in
Whole Core	3,525 – 3,575	Mt Simon Sandstone	4 in
Sidewall Core	Contingency	As Needed	1.5 in

Sidewall core intervals will be selected as contingency should the project be unable to obtain the desired whole core intervals. Using well logs, a neural network will be run to determine the heterogeneous rock types. This will be used to determine the sidewall core locations and to fill any gaps in the whole core program. Sidewall cores collected will provide a comprehensive set of routine rock property data for calibrating geophysical wireline logs and to supplement formation property data where whole core data are not available.

Additional core will be collected if:

- Interpretation of the characterization well data indicates that additional data are needed to meet Class VI permit requirements.
- As required by the Director.

Once the whole core is collected, preserved, and transported to a core lab, the following will be completed:

1. The core will be slabbed.
2. High resolution core photography will be completed.
3. Core viewing and core descriptions will be completed by project geologists.
4. Using well logs, a neural network will be run to determine the heterogeneous rock types.
5. To best capture the heterogeneity present in the core, the core viewing and heterogeneous rock type analysis will be used to select whole core plug locations.
6. Whole core plugs will be taken from the whole core at regular intervals.
7. Core analysis will be completed. Core testing will provide information on rock properties (e.g., porosity, permeability, petrology, and mineralogy) that are representative of the injection and confining zones near the injection well. Table 5 contains details of the planned laboratory testing for the whole core sections.

8. The details in Table 5 are a preliminary plan only and are expected to change once site-specific data is acquired. Core plugs, sidewall plugs, and core analysis will be adjusted based on the drilling and log data that is acquired.

If sidewall core is collected, preserved, and transported to a core lab, the following will be completed.

1. High resolution core photography will be completed.
2. Core viewing and core descriptions will be completed by project geologists.
3. Core analysis will be completed. Core testing will provide information on rock properties (e.g., porosity, permeability, petrology, and mineralogy) that are representative of the injection and confining zones near the injection well.

Core samples from the second deep well will provide information on geologic properties in the immediate area. The laboratory-derived core measurements will be integrated with wireline logs and used for petrophysical calibration. The integrated dataset will then be correlated with wireline logs from offset wells to support the correlation and confirmation of stratigraphy, rock properties, and site characterization.

Formal core plans and numbers of cores to be utilized for each analysis listed in Table 5 will be provided once they are finalized with a coring contractor prior to well installation.

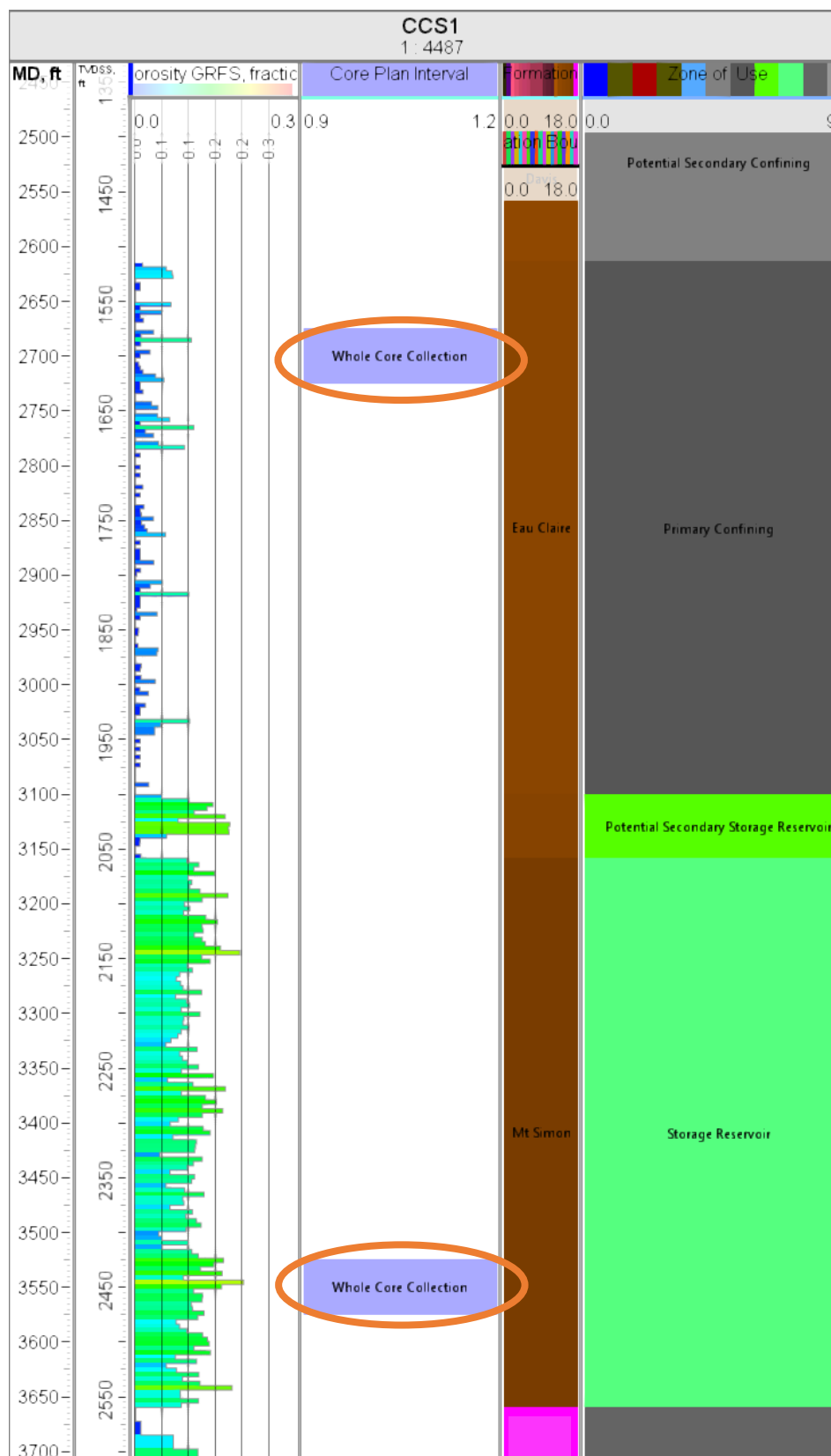


Figure 4: Preliminary whole core collection plan

**Table 5: Summary of potential core analyses and associated parameters**

<b>Core Analysis Type</b>	<b>Parameters Obtained</b>	<b>Formations</b>
Routine Core Analysis	Porosity, Permeability, Grain Density	Mt. Simon Sandstone Eau Claire Shale Intervals TBD
Tight Rock Analysis	Porosity, Permeability, Grain Density	Eau Claire Shale Intervals TBD
Thin-Section Petrography	Mineralogy, Lithology, Porosity, Grain size, Textural maturity, Oil Staining	Mt. Simon Sandstone Eau Claire Shale Intervals TBD
X-Ray Diffraction	Mineralogy, clay identification	Mt. Simon Sandstone Eau Claire Shale Intervals TBD
Core Gamma Ray Log	Lithology, Porosity, Grain Size, Geologic Contacts	Both Whole Core Intervals
Relative Permeability	Relative permeability, Wettability	Mt. Simon Sandstone Intervals TBD
Mercury Injection Capillary Pressure	Capillary Pressure	Mt. Simon Sandstone Eau Claire Shale Intervals TBD
Triaxial Tests	Rock Strength, Ductility, Poisson's Ratio, Young's Modulus	Mt. Simon Sandstone Eau Claire Shale Intervals TBD
Rock Compressibility	Rock Compressibility	Mt. Simon Sandstone Eau Claire Shale Intervals TBD

### **3.5 CCS1 Injection Well: Fluid Sampling and Analysis (146.87 (b – d))**

Characterization of formation fluids will be based on analysis of fluid samples acquired from USDW1, CCS1, and ACZ1. These samples will be collected through swabbing, drill stem tests (DSTs), or downhole pumps and will provide information on the baseline geochemistry of the subsurface fluids. The sampled formations will include, but are not limited to, the injection formation, the first ACZ monitoring interval above confining zone, and the lowermost USDW.

All fluid samples will be analyzed for TDS, other major analytes, and stable isotopes. This list of analytes as well as their detection limits is provided in Table 6.

**Table 6. Summary of analytical and field parameters for groundwater samples**

Parameters	Analytical Methods <sup>(1)</sup>
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Ti Ca, Fe, K, Mg, Na, and Si	ICP <sup>(2)</sup> -MS <sup>(3)</sup> , EPA Method 6020 ICP-OES <sup>(4)</sup> , EPA Method 6010B
Anions: Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0
Dissolved CO <sub>2</sub>	Coulometric Titration ASTM D513-11
Stable Isotopes of $\delta^{13}\text{C}$ Dissolved Inorganic Carbon (DIC)	Isotope Ratio Mass Spectrometry <sup>(5)</sup>
Total Dissolved Solids (TDS)	Gravimetry APHA 2540C
Water Density (field)	Oscillating Body Method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Conductivity/Resistivity (field)	APHA 2510
Temperature (field)	Thermocouple
<p>Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.</p> <p>Note 2: Inductivity Coupled Plasma</p> <p>Note 3: Mass Spectrometry</p> <p>Note 4: Optical Emission Spectrometry</p> <p>Note 5: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)</p>	

### 3.6 Geomechanical Testing (146.87 (d))

The geomechanical characterization of the injection and confining zones for the project will be assessed by analyzing one or more of the following data sets: core analyses, log data, and in-situ field tests. These analyses may include, but are not limited to, triaxial compressive strength tests of core samples, dipole sonic and image logs, and step rate testing (SRT). The results of these analyses will provide information on the direction and magnitude of the three principal components of the stress field as well as the fracture gradient. Additional geomechanical data may be collected from OBS1 if problems are encountered with data acquisition in CCS1.

An SRT will be performed on the Mt. Simon Sandstone interval to determine the following information:

- Fracture opening pressure (to determine the fracture gradient)
- Fracture propagation pressure
- Fracture closure pressure.

This will be done by analyzing the pressure response to increasing rates. Injection at each of these rates will be performed on CCS1 for the same period as the high-level procedure below.

A formal procedure will be provided to the EPA prior to the running of the SRT.

1. Record static pressure and temperature for a minimum of one hour.
2. Rig-up pump truck, ensure sufficient volume of fluid is present at location to begin testing.
3. Pressure test lines above maximum anticipated operating pressure, but below equipment rating.
4. Begin SRT.
  - a. Pump first step of test at first desired rate (ex: 0.5 bpm) for a defined time (ex: 0.5 hours)
  - b. After the first step is completed, increase rate to next step (ex: 1.0 bpm) for the same defined step time (0.5 hours).
  - c. Repeat until the end of the test.
5. Shut-in well at the wing valves(s). Record the time of shut-in, the rate prior to shut-in and the shut-in pressure.
6. Rig-down pump truck.
7. Monitor pressure falloff for minimum of 24-hours.

The data from this test will be analyzed using appropriate analysis software, and the results will be included in the post installation reporting. Gauge calibration records will be provided at this time as well.

### **3.6.1 Pressure Fall-off Testing**

A pressure fall-off test (FOT) will be run on CCS1 following the completion of the SRT. The purpose of this test is to further characterize the injection zone. During this test, fluid will be injected at a constant rate for a predetermined length of time, after which the well is shut in, and the FOT monitored for an equal amount of time as the injection lasted.

The data from this test will be evaluated using rate superposition analysis to determine reservoir information such as: permeability, skin factor (damage), and flow regimes present. This test analysis will act as a “baseline” measure to determine the change in overall effectiveness and injectivity of the injection zone over time, among other things. A high-level procedure is provided below. Note that a formal procedure will be provided to the EPA prior to the running of the FOT.

1. Record static pressure and temperature for a minimum of one hour.
2. Rig-up pump truck, ensure sufficient volume of fluid is present at location to begin testing.
3. Begin injection. Inject at constant rate for predetermined duration.
4. At the end of the injection period, shut the well in at the wing-valve(s). Record the time of shut-in, rate prior to shut-in, and the shut-in pressure.
5. Secure the well.

6. Rig-down pump truck
7. After the pressure has been allowed to decline for approximately the same duration as the injection the test can conclude.

The data from this test will be analyzed using pressure transient analysis software, and the results will be included in the post installation reporting. Gauge calibration records will be provided at this time as well.

### **3.7 CCS1 Injection Well Mechanical Integrity Testing (146.87 (a)(4))**

#### **3.7.1 Internal Mechanical Integrity Testing (146.87 (a)(4)(i))**

Internal mechanical integrity (Part I) refers to the integrity of the seal between the long string casing, injection tubing, wellhead, and packer as well as the integrity of the individual components. In this subsection, annulus refers to the casing-tubing annulus. The effectiveness of this seal can be confirmed with a mechanical integrity test (MIT) and annular pressure monitoring.

Part I of the mechanical integrity will be demonstrated by way of an annulus pressure test (APT) as is standard for UIC wells. The APT will be performed after the tubing, packer, downhole equipment, and the wellhead have been installed. Prior to the installation of the wellhead, the annulus will be filled with fluid as outlined in the Well Construction component of this application (Attachment 4: Well Construction, 2022).

The APT will then be performed by pressuring up the annulus after the well has reached thermal equilibrium. Once this has occurred, the annulus will be pressured up to 1,500 psi as outlined later in the application (Attachment 6: Well Operations, 2022). A calibrated digital gauge will be installed on the annulus, and the pressure will be monitored for a period no less than 60-minutes.

During this period, the casing and tubing pressure will be monitored at 5-minute intervals. Following the conclusion of the test, the gauge will be removed, and the casing pressure will be lowered to the normal operational pressure. The test will be considered successful if the pressure has deviated by less than 5% of the initial value.

In addition to this standard internal integrity monitoring, inspection of the tubing will be performed as it is being installed to monitor the tubing for corrosion (Attachment 7: Testing And Monitoring, 2022).

Once injection commences, injection pressure, annular pressure, and annular fluid volumes will be monitored continuously to ensure internal well integrity and proper annular pressure is maintained (Attachment 7: Testing And Monitoring, 2022).

#### **3.7.2 External Mechanical Integrity (146.87 (a)(4)(ii – iv))**

External mechanical integrity (Part II) refers to the absence of fluid movement/leaks through channels in the cement between the long string casing and the borehole. The upward migration

of injected fluids through this zone could result in contamination of USDWs. The external integrity of CCS1 will be confirmed throughout the project. The frequency of the testing to determine Part II mechanical integrity will be performed on the schedule defined in the testing and monitoring plan (Attachment 7: Testing And Monitoring, 2022).

Generally accepted methods for evaluating external mechanical integrity include the following:

- Temperature or noise log,
- Oxygen-activation logging (OAL) or radioactive tracer (RAT) logging (during operation)

After completion, a baseline temperature log will be run from surface to the bottom of the long string casing (approximately 3,693 ft) to provide initial temperature conditions over the well. Temperature logging performed after injection has started will be performed at regular intervals based on the schedule provided in the testing and monitoring plan. The results of these logs will be compared to the baseline log to determine if anomalies that suggest CO<sub>2</sub> is migrating up the well bore are present.

If the temperature logging data suggests an issue with external well integrity exists, a RAT log will be performed to evaluate external well integrity with greater sensitivity.

In addition to the baseline temperature log, a CBL, and advanced ultrasonic cement evaluation log will be run across the entire long casing string after completion of the injection well to confirm that the casing string was properly cemented. Cement Bond Logs-Variable Density Logs (CBL-VDLs) are recorded with sonic tools that detect the bond of the casing and formation to the cement between the casing and wellbore to identify damage. Ultrasonic tools provide higher accuracies and resolutions for cement evaluation.

### 3.8 CCS1 Injection Well Schedule (146.87 (f))

Cardinal Ethanol will provide Region 5 with the opportunity to witness all logging and testing detailed in this section. Cardinal Ethanol will submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test, as much as reasonably possible.

Table 7 provides a tentative schedule based on the numbers of days to complete each well and the associated data to be collected. It is anticipated that the drilling schedule can be updated once CCS1 has been drilled, and once again when the Class VI permit is received.

The Pre-Operational Formation Testing Program for CCS1 consists of the following primary steps that are subject to change as circumstances dictate.

1. Determine the depth to the deepest USDW so surface casing can be set.
  - a. Note: *This depth will be determined based on prior testing performed on USDW1, assuming that the lowest USDW is identified and tested.*
2. Drill the surface hole to the surface casing depth.
  - a. Note: *It is anticipated that the TD of the surface section will be between 450-600 feet, depending on the results from Step 1. Deviation surveys will be taken using method described in Section 3.1 of this document.*
3. Log the surface hole with open hole logs.
  - a. Note: *a list of these logs is provided in Table 2 above.*
4. Install the surface casing and cement in place per the methodology described in the Well Construction Program (Attachment 4: Well Construction, 2022).
5. To ensure the isolation of the lowermost USDW and to confirm the integrity of cement-casing and cement-formation bond, a cement bond log will be run. Following this, and prior to drilling out the surface casing shoe, a casing pressure test will be completed.
  - a. Note: *details on the casing pressure test are provided in (Attachment 4: Well Construction, 2022).*
6. Once the surface casing is cemented, tested and a good bond log has been run, the rig will drill through the surface casing shoe, then drill the well to TD. Sufficient rat hole will be drilled at such that the basement rock can be properly characterized.
  - a. Note: *the anticipated TD of the well is approximately 3,708 feet, but is subject to change*
7. If, during drilling, a substantial lost circulation zone is encountered, an intermediate casing string will be used to isolate this zone.
  - a. Note: *Steps 3, 4, and 5 will be completed to characterize this section of the formation and to confirm good cement bonding is present. A list of the logs to be run in this section is provided in Table 3.*
8. The well will be logged with open hole logs.
  - a. Note: *a list of these logs is provided in Table 4.*
9. Assuming CCS1 is drilled first, whole core depths will be determined from CCS1 to guide coring depths in OBS1 in order to collect core from the reservoir and confining zone intervals. Sidewall core will be collected as required to fill in data gaps.
10. The long string casing will be installed and cemented in place per the methodology described in the Well Construction Program (Attachment 4: Well Construction, 2022).
11. Select intervals of the Mt. Simon Sandstone will be perforated and cleaned with acid per the methodology described in the Well Construction Program (Attachment 4: Well Construction, 2022).

12. The injection string, packer and wellhead will be installed per the methodology described in the Well Construction Program (Attachment 4: Well Construction, 2022).
13. Part I (internal) and Part (external) mechanical integrity will be displayed.
14. Fluid samples will be taken from the Mt. Simon Sandstone and will be analyzed for TDS, other major analytes, and stable isotopes.
  - a. Note: further detail on the fluid sampling is provided in Section 3.5 of this document.
15. Geomechanical testing will be performed on the Mt. Simon Sandstone by means of an SRT to determine the in-situ fracture pressure of the formation.
16. Geomechanical testing will be performed on the core taken from the Eau Claire Formation as detailed in Section 3.4 of this document.
17. A pressure falloff test (FOT) will be performed on the well to determine reservoir parameters.

A detailed proposed scheduled and time breakdown (drilling curve) is provided in the well construction section.

**Table 7: Tentative Schedule for Pre-Operational Testing**

Well	Depth (ft)	Days	Data Sets
USDW1	600	3	1. USDW water quality sample
CCS1	3,708*	20	1. Open hole logs 2. Special open hole logs 3. Cased hole logs 4. Mt. Simon Sandstone fluid sample(s) 5. Whole or sidewall core collected in OBS1 6. Geomechanical and reservoir testing
OBS1	3,709*	20	1. Open hole logs 2. Cased hole logs 3. Whole or sidewall core (Mt. Simon Sandstone and Eau Claire Shale)**
ACZ1	1,600	10	Any potential missing data sets
*Only one well will be drilled into basement. The well which does not penetrate the basement will be drilled to a shallower depth than listed **OBS1 could also be used as the primary core collection well. Should sidewall cores be needed, they can also be collected from this well.			

#### **4 References**

- (2022). *Attachment 1: Narrative*. Class VI Permit Application Narrative; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 10: ERRP*. Emergency And Remedial Response Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 11: QASP*. Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 2: AOR and Corrective Action*. Area Of Review And Corrective Action Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 3: Financial Responsibility*. Financial Responsibility; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 4: Well Construction*. Injection Well Construction Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 5: Pre-Op Testing Program*. Pre-Operational Formation Testing Program; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 6: Well Operations*. Well Operation Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 7: Testing And Monitoring*. Testing And Monitoring Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 8: Well Plugging*. Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 9: Post-Injection Site Care*. Post-Injection Site Care And Site Closure Plan; Hoosier#1 Project, Vault 4401.

### Tentative Schedule for Pre-Operational Testing

A detailed proposed scheduled and time breakdown (drilling curve) is provided in the well construction section.

**Table 1: Tentative Schedule for Pre-Operational Testing**

Well	Depth (ft)	Days	Data Sets
USDW1	600	3	1. USDW water quality sample
CCS1	3,708*	20	1. Open hole logs 2. Special open hole logs 3. Cased hole logs 4. Mt. Simon Sandstone fluid sample(s) 5. Whole or sidewall core collected in OBS1 6. Geomechanical and reservoir testing
OBS1	3,709*	20	1. Open hole logs 2. Cased hole logs 3. Whole or sidewall core (Mt. Simon Sandstone and Eau Claire Shale)**
ACZ1	1,600	10	Any potential missing data sets
<p>*Only one well will be drilled into basement. The well which does not penetrate the basement will be drilled to a shallower depth than listed</p> <p>**OBS1 could also be used as the primary core collection well. Should sidewall cores be needed, they can also be collected from this well.</p>			

## Class VI UIC Project Plan Submissions

This submission is for:

Project ID: R05-IN-0003

Project Name: Project Hoosier #1

Current Project Phase: Pre-Injection Prior to Construction

### Testing and Monitoring

Are You Making a Testing and Monitoring Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Testing and Monitoring Plan: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/7.--Testing--and--Monitoring--Plan\\_Hoosier--1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/7.--Testing--and--Monitoring--Plan_Hoosier--1.pdf)

Appendices and Supporting Materials Upload

Attach Any Supporting Documentation for the Testing and Monitoring Plan: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/11.--QASP\\_Template--Hoosier--1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/11.--QASP_Template--Hoosier--1.pdf)

### Injection Well Plugging

Are You Making an Injection Well Plugging Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Injection Well Plugging Plan: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/8.--Injection--Well--Plugging--Plan\\_Hoosier--1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/8.--Injection--Well--Plugging--Plan_Hoosier--1.pdf)

Appendices and Supporting Materials Upload

### PISC and Site Closure

Are You Making a Post-Injection Site Care and Site Closure Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Post-Injection Site Care and Site Closure Plan: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/9.--PISC--and--Site--Closure--Plan\\_Hoosier--1--.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/9.--PISC--and--Site--Closure--Plan_Hoosier--1--.pdf)

Appendices and Supporting Materials Upload

### Emergency and Remedial Response

Are You Making an Emergency and Remedial Response Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Emergency and Remedial Response Plan: [https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\\_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/10.--Emergency--and--Remedial--Response--Plan\\_Hoosier--1.pdf](https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IN-0003/Phase1-PreConstruction/ProjPlan-07-07-2022-1139/10.--Emergency--and--Remedial--Response--Plan_Hoosier--1.pdf)

Appendices and Supporting Materials Upload

### Complete Submission

Authorized submission made by: Ricky Weimer

For confirmation a read-only copy of your submission will be emailed to: craig@vault4401.com

**ATTACHMENT 7: TESTING AND MONITORING PLAN**  
**40 CFR 146.90**  
**HOOSIER #1 PROJECT**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
Cardinal Ethanol

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CO<sub>2</sub> Injection Well Location for Cardinal\_CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

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## **List of Acronyms**

3D	Three-dimensional
ACZ	Above Confining Zone
ACZ1	Above Confining Zone Well
AoR	Area of Review
APT	Annular Pressure Test
BGS	Below Ground Surface
BHFP	Bottomhole Flowing Pressure
CO <sub>2</sub>	Carbon Dioxide
CCS1	Proposed Injection well
DIC	Dissolved Inorganic Carbon
DTS	Distributed Temperature Sensor
EPA	Environmental Protection Agency
EPSCG	European Petroleum Survey Group
ERRP	Emergency and Remedial Response Plan
FOT	Fall-off Test
GR	Gamma Ray
ICP	Inductivity Coupled Plasma
IBDP	Illinois Basin – Decatur Project
MAIP	Maximum Allowable Injection Pressure
Mc	Magnitude of completeness
MIT	Mechanical Integrity Test
MS	Mass Spectrometry
OBS1	Deep Observation Well
OES	Optical Emission Spectrometry
PISC	Post Injection Site Care
PNL	Pulsed Neutron Logging
PSI	Pound per Square Inch
QA	Quality Assurance
QASP	Quality Assurance and Surveillance Plan
RAT	Radioactive Tracer
SCADA	Supervisory Control and Data Acquisition

Plan revision number: 1.0  
Plan revision date: July 4, 2022

TBD	To Be Determined
TD	Total Depth
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USDW1	Lowermost USDW monitoring well

## **1 Overall Strategy and Approach for Testing and Monitoring**

This Testing and Monitoring Plan presented in this document provides details on how the Hoosier #1 Project will monitor the site pursuant to 40 CFR 146.90.

### **1.1 Testing and Monitoring Plan Strategy**

The Hoosier #1 Project has developed a risk-based Testing and Monitoring Program that includes operational, verification, and environmental assurance components while, at the same time, meeting the regulatory requirements of 40 CFR 146.90 (Attachment 1: Narrative, 2022; Attachment 12: Risk Register, 2022). This Testing and Monitoring Program is based on experience gained from other approved Class VI projects, as well as extensive geologic evaluation and computational modeling.

Goals of the monitoring strategy include, but are not limited to:

- Fulfillment of the regulatory requirements of 40 CFR 146.90,
- Protection of underground sources of drinking water (USDW),
- Risk mitigation over the life of the project,
- Confirmation that CCS1 is operating as planned while maintaining mechanical integrity,
- Acquisition of data to validate and calibrate the models used to predict the distribution of CO<sub>2</sub> within the injection zone,
- Support Area of Review (AoR) re-evaluations over the course of the project.

The Testing and Monitoring Plan will be adaptive over time, and is subject to alteration should one of the following potential scenarios occur:

- Project risks evolve over the course of the project outside of those envisioned at the beginning of the project,
- Significant differences between the monitoring data and predicted computational modeling results are identified,
- Key monitoring techniques indicate anomalous results related to well integrity or the loss of containment.

Monitoring activities can be separated into three categories based on various objectives: operational, verification, and assurance monitoring.

- *Operational monitoring* focuses on day-to-day injection operations such as system performance.
- *Verification monitoring* confirms that the CO<sub>2</sub> remains contained within the selected storage complex. The CO<sub>2</sub> and pressure plume development is tracked over time to provide data for model calibration. Integration of verification monitoring data into project models allows the project to demonstrate conformance between the computational modeling and the testing and monitoring data collected during the operations and closure phases of the project's lifecycle.

- *Assurance monitoring* is at surface and near-surface (i.e., soil, groundwater, USDWs, etc.) to monitor for any changes from baseline (taken pre-injection) sample data that might indicate CO<sub>2</sub> migration towards surface.

These three categories cover a range of monitoring objectives including

- Well operations,
- Containment,
- Non-endangerment of USDWs,
- Capacity,
- Injectivity,
- Injection pressure, and
- Conformance.

Table 1 provides of summary of the general monitoring strategy with subcategories.

**Table 1: Summary of general monitoring strategy for the Hoosier #1 Project**

Monitoring Action	Monitoring Objectives	Monitoring Technology
CO <sub>2</sub> stream analysis	Purity of the CO <sub>2</sub> stream	Lab analysis
CO <sub>2</sub> plume monitoring	Verification/ conformance, containment, non-endangerment of USDWs	Time-lapse seismic data, pulsed neutron logging (PNL), fluid sampling with aqueous geochemistry, and isotope analysis
Pressure plume monitoring	Injection pressure, injectivity, verification/ conformance	Downhole pressure sensors in the injection wells, microseismic monitoring
ACZ Changes	Containment, non-endangerment of USDWs	Downhole pressure and temperature sensors in monitor wells, fluid sampling with aqueous geochemistry and isotope analysis, PNL, time-lapse seismic data,
Project well integrity	Containment, non-endangerment of USDWs	Temperature logging, PNL, oxygen activation or radioactive (RAT) logging, annular pressure monitoring, mechanical integrity tests (MIT), pressure fall-off tests (FOTs), corrosion monitoring, testing of emergency shut-down systems
Reservoir performance	Injectivity	Wellhead and downhole pressure sensors
Induced seismicity	Containment, non-endangerment of USDWs, induced seismicity	Surface-based or downhole microseismic monitoring arrays
Groundwater monitoring	Containment, non-endangerment of USDWs, assurance	Fluid sampling with aqueous geochemistry and isotope analysis

## **1.2 Storage Complex**

A site-specific stratigraphic chart of geologic formations present in CCS1 is shown in Table 2.

Figure 3 shows a cross section of the CO<sub>2</sub> plume at the end of the 10-year Post Injection Site Care (PISC) period.

The specific intervals to be monitored are as follows:

- Mt. Simon Sandstone (injection interval),
- Above Confining Zone (ACZ) (likely in the Knox Formation),
- Maquoketa Shale (suspected lowermost USDW),
- Shallow groundwater.

As a result of the scarcity of well data below the Trenton Formation, the final ACZ monitoring interval will be determined after the first deep well has been drilled for the project. Based on regional knowledge, it is expected that a suitable monitoring interval will be found at or immediately below the Knox Formation unconformity due to the Glenwood Formation's properties that will create an effective barrier to fluid migration in Ohio.

**Table 2: Major stratigraphic units in the AoR with descriptions and role in the project.**

Period	Group	Formation	Use	Brief Description
	Undifferentiated		Undifferentiated	The deepest USDW is estimated to be at 450 feet.
	Silurian Bedrock			
Ordovician	Maquoketa	Maquoketa	Lowermost USDW	
		Kope	Undifferentiated	Unconsolidated glacial deposits
		Trenton	Gas Production	Gas production target to be avoided
	Black River	Black River	Undifferentiated	Unconsolidated
		Pecatonica		
	Ansell	Joachim		
		Gull River		
		Glenwood		
	Knox	Knox	Monitoring Interval	The Knox is composed of white to brown, very fine to coarse-grained, crystalline to sugary dolomite, containing pyrite, white and light blue oolitic chert, and dolomite rhombs with fossil fragments. Portions of the Knox are vuggy and thus the unit contains some intervals capable of acting as buffering units.
		Shakopee	Potential Secondary Confining  (approx. 988 ft thick)	
		Oneota		
		Potosi		
Cambrian		Davis	Primary Confining  (approx. 487 ft thick)	Interbedded shales, and dolomite. Interbedded green and reddish-brown glauconitic shales are more prevalent near the top of the formation.
		Eau Claire		
	Potsdam	Eau Claire Silt	Potential Secondary Storage Reservoir (Storage rights requested)  (approx. 59 ft thick)	Interbedded glauconitic sandstones, siltstones, shales. Siltstones and sandstones are light to medium greenish-gray, brown, or very light orange.
		Mt Simon	Storage Reservoir (Storage rights requested)  (approx. 501 ft thick)	Lies unconformably upon the Middle Run (Precambrian). This is evident by the abrupt change from the poorly sorted, heterogenous, angular, well cemented rocks of the Middle Run and the lighter, homogenous, less cemented partially friable basal Mt. Simon Sandstone.
	Precambrian	Precambrian	Middle Run and Precambrian and Basement	Lower Confining

### 1.3 Area of Review and Project Wells

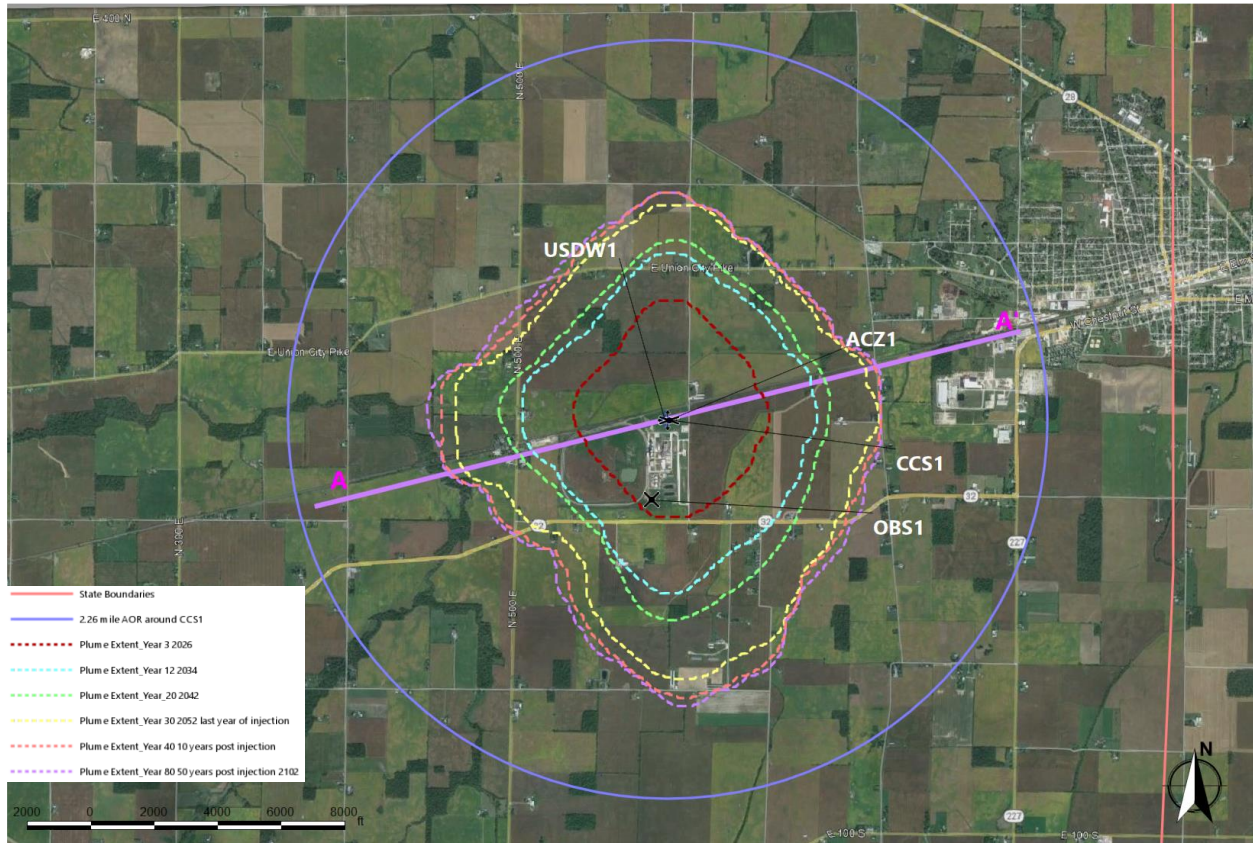
Figure 1 and Table 3 show the proposed wells for the project. Figure 1 shows the predicted plume development over time as well as the AoR. Figure 2 and Figure 3 illustrate the modeled CO<sub>2</sub> plume development ten-years post injection as well as the current AoR. The current CO<sub>2</sub> and pressure plume predictions have been used to inform the spatial extent of the Testing and Monitoring Plan.

The AoR and Corrective Action Plan includes a discussion of the technical basis for the current AoR as well as how the monitoring data will be used to re-evaluate the AoR over the injection phase of the project (Attachment 2: AoR and Corrective Action, 2022). Once CCS1 has been drilled, the data gathered as part of the Pre-Operational Testing Program will be used to update the current static model and the computational modeling (Attachment 5: Pre-Op Testing Program, 2022). The updated models will be used to verify or re-evaluate the current AoR and associated Testing and Monitoring Plan should it be necessary (Attachment 2: AoR and Corrective Action, 2022).

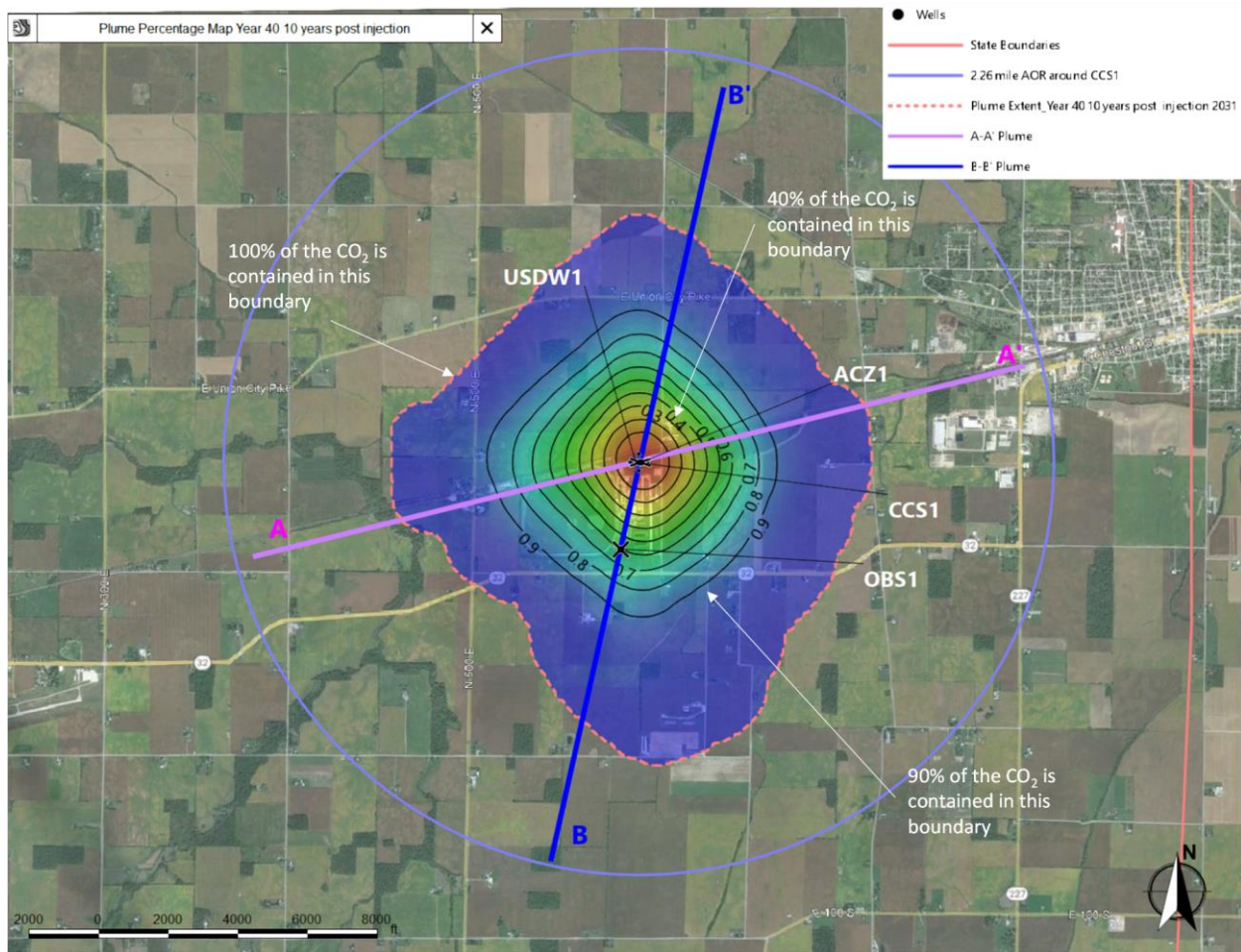
The proposed OBS1 well is located approximately 2,500 ft south of CCS1 and the Cardinal Ethanol facility on land owned by Cardinal Ethanol (Figure 2). The computational modeling predicts that the CO<sub>2</sub> will breakthrough at this well in the Year 3 of injection operations (Attachment 2: AoR and Corrective Action, 2022). The primary objectives of the OBS1 well are to monitor injection zone pressures at a distance from CCS1 and to obtain fluid samples from the well prior to CO<sub>2</sub> breakthrough. Fluid samples from the injection zone will allow the project to characterize the changes in aqueous geochemistry and the rock matrix in the early years of the project. Once the CO<sub>2</sub> breaks through at OBS1, the project will be able to use PNL to characterize the development of the vertical CO<sub>2</sub> plume over time at a distance from CCS1. The far field pressure measurements will be used to calibrate the computational modeling during the operations phase of the project.

**Table 3: Proposed Hoosier #1 Well Locations (European Petroleum Survey Group (EPSG) 2965)**

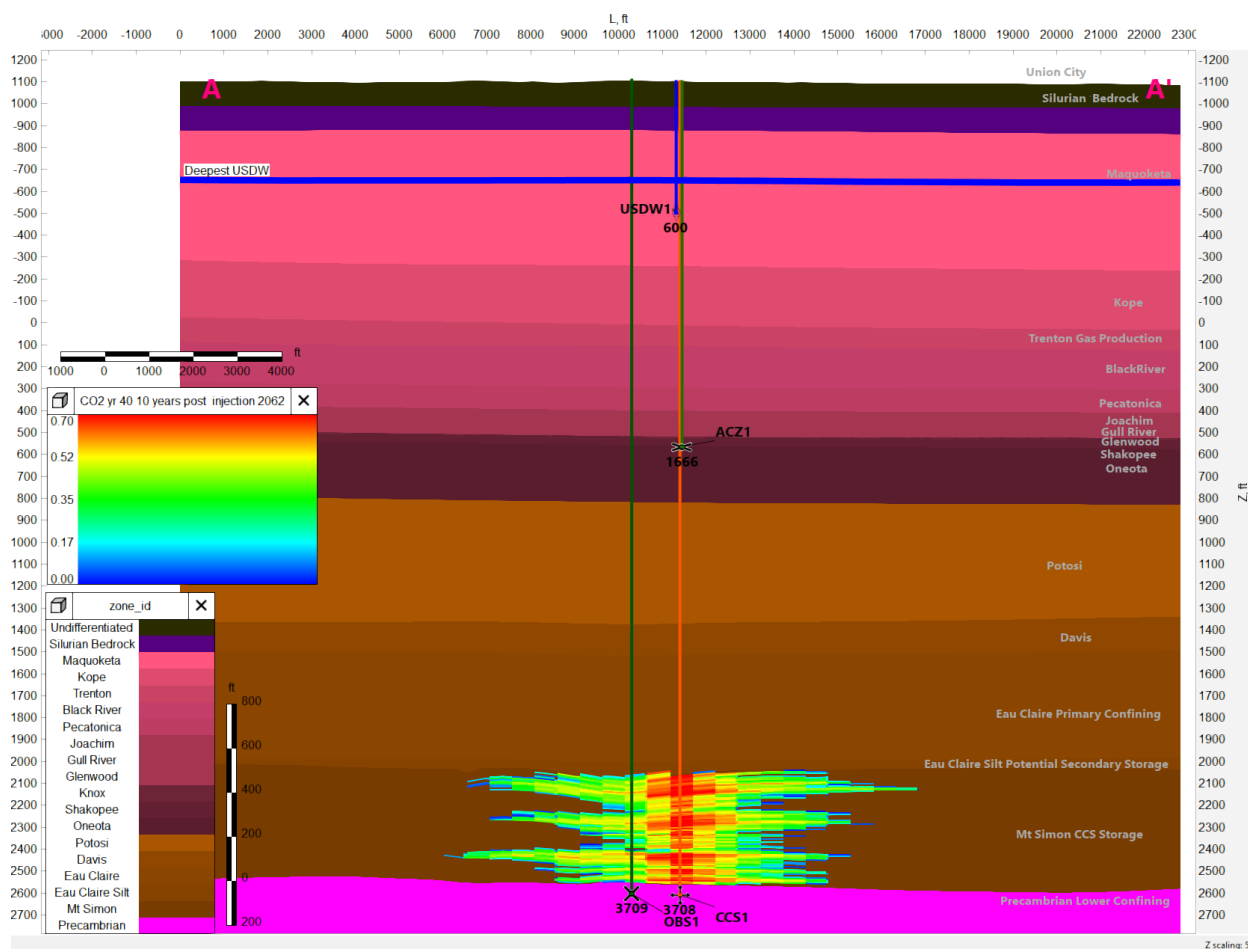
Well Name	Well Use	X0, ft	Y0, ft	TD, ft	Status
CCS1	Primary CCS Injector well in the Mt. Simon Sandstone	552167	1799966	3,708	Proposed Wells
OBS1	CCS Observation Well	551657	1797463	3,709	
ACZ1	ACZ Monitoring Well	552218	1799966	1,666	
USDW1	Lowermost USDW Monitoring Well	552080	1799966	600	



**Figure 1: Time-lapse CO<sub>2</sub> plume development map over 3, 12, 20, and 30 years of injection as well as 10- and 50-years post injection. Note the relative stability of the CO<sub>2</sub> plume radius after injection operations cease.**



**Figure 2: CO<sub>2</sub> plume after 30-years of injection and 10-years post injection. Contour intervals indicate the volume of CO<sub>2</sub> contained within the contour bounds. Project AoR is indicated by the blue circle.**



**Figure 3: A-A Cross-section of the CO<sub>2</sub> plume after 30 years of injection and 10 years post injection through CCS1 and OBS1. Well total depths (TDs) are annotated for each well.**

## 1.4 Summary of Testing and Monitoring Plan Components

Operational monitoring serves to ensure all procedures and processes associated with the project are safe and well integrity is maintained. Continuously recorded data that will monitor the response of the injection zone includes:

- Injection rate and volume,
- Wellhead injection pressure,
- Injection well annulus pressure and fluid volume, and
- Mt. Simon Sandstone pressure and temperature.

The verification monitoring will provide data that will be used to evaluate the vertical and horizontal CO<sub>2</sub> plume development over time and identify any potential CO<sub>2</sub> migration beyond the confining zone. The primary components of the CO<sub>2</sub> plume monitoring consist of PNL in the project wells and time-lapse three-dimensional (3D) surface seismic monitoring. The pressure plume development will be monitored with downhole pressure sensors in CCS1 and OBS1 as well as continuous microseismic monitoring.

The assurance monitoring component of the program will monitor the shallow groundwater aquifers for any indications that injection zone fluids have migrated into the near surface. Fluid samples will be taken from shallow groundwater aquifers on a regular basis to analyze the aqueous geochemistry and stable isotopes.

One of the primary goals of the testing and monitoring plan is to continue to demonstrate the activities of this project are safe for the health of the public and environment. In order to help facilitate this demonstration, the Quality Assurance and Surveillance Plan (QASP) has been developed to ensure the quality of the demonstration methods meet the requirements of the EPA Underground Injection Control (UIC) Program for Class VI wells.

Table 4 shows a summary of the activities, monitoring points, and purpose of each activity in the Testing and Monitoring Plan. The activities are discussed on more detail in sections that follow the table in this document.

**Table 4: Summary of Testing and Monitoring Activities**

<b>Activity</b>	<b>Location(s)</b>	<b>Purpose</b>
<b>CO<sub>2</sub> stream analysis</b>		
CO <sub>2</sub> stream analysis – downstream	CO <sub>2</sub> Delivery Pipeline	Monitor injectate quality and composition
<b>Continuous Recording</b>		
Injection rate	CCS1 Wellhead	Monitoring injection rate
Injection volume	CCS1 Wellhead	Calculated injection volume
Injection pressure	CCS1 Wellhead	Monitoring injection pressure
Wellhead pressure	ACZ1 Wellhead	
Annular pressure	CCS1 Wellhead OBS1 Wellhead	Monitoring annulus pressure
Downhole pressure	CCS1 Injection Interval OBS1 Injection Interval	Monitoring injection zone
Downhole temperature	CCS1 Wellbore	Monitoring injection zone, wellbore integrity
Microseismic monitoring	Various Monitoring Stations	Injection zone and confining zone integrity
<b>Well Integrity</b>		
Corrosion monitoring	CO <sub>2</sub> Delivery Pipeline CCS1 Wellhead	Monitoring injectate, wellbore integrity
Annular fluid volume	CCS1 Wellhead OBS1 Wellhead	Monitoring annulus fluid volume changes
Mechanical integrity (internal)	CCS1 Wellhead OBS1 Wellhead	Wellbore integrity
Mechanical integrity (external)	CCS1 Wellbore OBS1 Wellbore (temp log only)	Wellbore integrity
Cement Evaluation	CCS1 Wellbore OBS1 Wellbore ACZ1 Wellbore	Wellbore integrity
<b>Plume Tracking</b>		
PNL	CCS1 Wellbore OBS1 Wellbore	CO <sub>2</sub> saturation, vertical plume development
Downhole pressure	OBS1 - Injection Interval CCS1 – Injection Interval	Monitoring injection zone pressure, plume monitoring, confining zone integrity
Microseismic Monitoring	Minimum of 5 stations TBD	Injection zone and confining layer integrity

Activity	Location(s)	Purpose
Time-lapse 3D Seismic Data	Area sufficient to image an 8.97 mi <sup>2</sup> plume	Indirect measurement of plume development and overburden
<b>Fluid Sampling</b>		
Shallow Ground Water Sampling (Glacial Drift)	12 wells spatially distributed throughout the AoR	Detection of changes in groundwater quality for the shallow USDWs.
Lowermost USDW Sampling (Maquoketa Shale)	USDW1	Detection of changes in the groundwater quality in the lowermost USDW.
Above Confining Zone Sampling (Knox Formation)	ACZ1	Detection of changes in groundwater quality above the confining zone.
Injection Zone Monitoring (Mt. Simon Sandstone)	OBS1	Detection of changes in groundwater quality, geochemistry, and CO <sub>2</sub> saturation in the injection interval.

#### 1.4.1 CO<sub>2</sub> Stream Analysis and Corrosion Monitoring

The chemical composition of the CO<sub>2</sub> stream will be monitored downstream of the final compression unit and upstream of CCS1 (40 CFR 146.90 (a)). Corrosion coupons composed of the same material as the well components and CO<sub>2</sub>-delivery pipeline will be placed in the delivery pipeline and analyzed on a quarterly basis for signs of corrosion and loss of mass that may be indicative of future potential well integrity issues (40 CFR 146.90 (c)). If signs of corrosion are identified in the coupons, this may trigger further well integrity testing (Section 6.2).

#### 1.4.2 Injection Well Monitoring

Injection operations will be monitored through a range of continuous, daily, and quarterly techniques as detailed in the (Attachment 6: Well Operations, 2022).

Continuous recording devices will monitor wellhead injection pressure, temperature, and mass flow rate (40 CFR 146.90 (b)). The injection mass flowrate will be directly measured at the surface in order to calculate the cumulative mass of injected CO<sub>2</sub> and ensure compliance with the permit injection limits. The storage formation injection volume will be calculated using the mass flowrate combined with the pressure and temperature conditions in the injection zone. The calculated injection volumes will, in turn, be used to update the computational models at regular intervals throughout the injection phase of the project (Attachment 2: AoR and Corrective Action, 2022).

The annular pressure between the tubing and the injection casing strings as well as the annular fluid volumes will also be monitored on a continuous basis (40 CFR 146.90 (b)). These data will be linked into a supervisory control and data acquisition (SCADA) system to record the operations data, control injection rates, or initiate system shutdown, if needed. The SCADA

system can also be used to adjust the volume of annular fluid, and thereby pressure, in the annular space to meet the operational and regulatory objectives.

#### 1.4.3 Mechanical Integrity Testing

In addition to the annular pressure and fluid volume monitoring, the well integrity of CCS1 and the observation well (OBS1) will be monitored using a range of internal and external mechanical integrity evaluation methods. The same methods of mechanical integrity testing (MIT) will be performed on each well.

##### 1.4.3.1 Internal Mechanical Integrity Testing

The regulatory standard for Part I MIT is performing an annular pressure test (APT). This test will be run to regulatory standards after the well completion to confirm internal integrity as per the (Attachment 6: Well Operations, 2022; Attachment 5: Pre-Op Testing Program, 2022). Further details on the APT standards and methods of performing it are provided in a later section in this document.

##### 1.4.3.2 External Mechanical Integrity Testing

The external mechanical integrity of the wells will be confirmed through annual temperature and PNL. These logs will be compared back to baseline logs to identify any unexpected deviations that could indicate CO<sub>2</sub> flow or accumulations behind the casing above the injection zone (40 CFR 146.90 (e)).

Further details on these logs and the methods of performing them will be provided in a later section in this document.

#### 1.4.4 Pressure and Temperature Monitoring

The bottomhole pressure and temperature will be measured continuously in the OBS1 well. These gauges will continuously record these data and transmit them to surface.

OBS1 will be located within the area of the predicted 30-year CO<sub>2</sub> plume radius; the CO<sub>2</sub> plume is expected to intersect the well within the first three years of injection (Figure 3). This well will allow for pressure and temperature monitoring as well as periodic fluid sampling in the Mt. Simon Sandstone. The variations in the pressure and temperature data will be used to calibrate and verify the computational modeling through the pre-operational, injection, and PISC phases of the project (40 CFR 146.90 (g)).

#### 1.4.5 Plume Monitoring

A pressure fall-off test (FOT) will be conducted in the Mt. Simon Sandstone in CCS1 after it is drilled to establish the hydrogeologic characteristics of the injection zone (Attachment 5: Pre-Op Testing Program, 2022). During the injection phase of the project, a FOT will be conducted in CCS1 at least once every five years unless increases in injection pressure indicate a need for a FOT sooner (40 CFR 146.90 (f)). The formation characteristics obtained through the FOT will be compared to the results from previous tests to identify any changes over time, and they will be used to calibrate the computational models.

OBS1 will be used to monitor pressure, temperature, and to collect fluid samples from the injection zone to monitor for changes in the aqueous geochemistry of the formation. It will also be used to verify when the leading edge of the CO<sub>2</sub> plume reaches the observation well.

PNL will be run in the CCS1 and OBS1 to monitor CO<sub>2</sub> saturations and vertical plume development adjacent to the wellbores. This logging can also be used to identify accumulations of CO<sub>2</sub> above the confining zone should there be leakage along the wellbore. Once the near wellbore region of CCS1 becomes fully saturated with CO<sub>2</sub>, routine logging of the injection interval will be suspended but will continue through the ACZ monitoring interval. At this point, logging will occur in OBS1 to monitor CO<sub>2</sub> plume development away from CCS1.

Both the pressure and log data will be used to calibrate and verify the computational modeling over the injection and PISC phases of the project.

Beyond the direct measurement techniques that the project will deploy, time-lapse 3D surface seismic data and microseismic monitoring will be used to monitor the development of the CO<sub>2</sub> plume and the associated pressure front through the injection and PISC phases (40 CFR 146.90 (g)).

High resolution time-lapse 3D surface seismic data will be used to qualitatively monitor the CO<sub>2</sub> plume development and calibrate the computational modeling results over time. The time-lapse 3D surface seismic data will also be used to verify CO<sub>2</sub> containment within the injection zone, as any CO<sub>2</sub> accumulations in the overburden would result in seismic anomalies that would differ from the baseline seismic data. Source and received spacing and line intervals, and the resulting trace density will be designed to deliver full offset, full azimuth baseline data of sufficient resolution to image the target horizons. The microseismic monitoring will be used to monitor for any induced seismic events within an 8 mi radius of CCS1 in the confining layer that might indicate potential impacts to containment.

#### 1.4.6 Shallow Groundwater Sampling and Monitoring

The shallow groundwater monitoring program will use twelve shallow groundwater wells spatially distributed within the AoR in near surface groundwater aquifers, and one dedicated groundwater monitoring well that will be drilled into the lowermost USDW (40 CFR 146.90 (d)).

It is expected that the deepest USDW will be at 450 ft below ground surface (BGS) based on nearby well data and reports from the Indiana Department of Natural Resources (Attachment 1: Narrative, 2022). The deepest USDW will be verified when USW1 is drilled as per the (Attachment 5: Pre-Op Testing Program, 2022).

Baseline groundwater samples will be acquired from these wells to help characterize the variations in water quality within the AoR prior to the start of CO<sub>2</sub> injection. In addition to the standard analytes, the groundwater samples will also have their aqueous geochemistry and stable isotopes analyzed.

Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry and stable isotope analyses will be compared to the baseline conditions for any indication of CO<sub>2</sub> or brine migration into the shallow groundwater aquifers. If indications of CO<sub>2</sub> or brine are found in the shallow groundwater aquifer, it will trigger the emergency response actions found in the Emergency and Remedial Response Plan (Attachment 10: ERRP, 2022).

#### 1.4.7 Deep Groundwater Sampling and Monitoring

One deep groundwater well (ACZ1) will be drilled into to a deep saline formation above the confining zone for the project. It is expected that this will be below the Knox Formation unconformity based on regional geology; however, a final determination will be made after the

first deep well for the project has been drilled. The ACZ1 well will be in close proximity to CCS1 to monitor a deep saline formation immediately above the confining layer assuming that fluid migration from the injection zone is most likely to occur along a wellbore.

ACZ1 will be used to take fluid samples and monitor pressure changes in the selected saline formation (40 CFR 146.90 (d)). Injection zone fluid migration past the confining layer and into the ACZ monitoring zone will most likely be identified through pressure changes in the formation. Pressure will be monitored at the wellhead.

#### 1.4.8 Microseismic Monitoring

The project site is located in an area with low rates of natural seismic activity and risk (Attachment 1: Narrative, 2022). It is not expected that natural seismicity will affect the project. The Illinois Basin – Decatur Project (IBDP) injected CO<sub>2</sub> into the basal section of the Mt. Simon Sandstone, and generated microseismic events throughout the injection phase of the project despite injecting CO<sub>2</sub> below fracture pressure (Bauer, 2016). This project plans to inject above the basal section of the Mt. Simon Sandstone and will monitor related microseismic activity to assist in managing project risks (Attachment 10: ERRP, 2022; Attachment 12: Risk Register, 2022).

The microseismic monitoring will be used to accurately determine the locations and magnitudes of injection-induced seismic events with the primary goals of:

- Addressing public and stakeholder concerns related to induced seismicity,
- Monitoring the spatial extent of the pressure front from the distribution of microseismic events within an 8 mi radius of CCS,
- Identifying activity that may indicate failure of the confining zone and possible containment loss.

A surface-based microseismic monitoring array will be designed with microseismic monitoring stations at a range of azimuths to optimize the accuracy of the event locations and magnitudes. This network can easily be expanded in response to monitoring results or future AoR re-evaluations, if necessary.

#### 1.4.9 General Testing and Monitoring Activity Frequency

Table 5 presents the general schedule and spatial extent for the monitoring activities in the baseline and injection phases of the project based on the current understanding of the site. Refer to the (Attachment 9: Post-Injection Site Care, 2022) for discussion of the PISC monitoring plans.

The depth of investigation ranges will be updated once the data from CCS1 has been analyzed and the static model has been updated.

Changes to the monitoring schedule may occur over time as the project evolves. Any such changes to the testing and monitoring plan or the PISC will be made in consultation with the UIC Program Director (40 CFR 146.90 (j)).

**Table 5: General schedule and spatial extent for the testing and monitoring activities for the Hoosier #1 Project**

<b>Monitoring Activity</b>	<b>Baseline Data Frequency</b>	<b>Injection Phase Frequency*</b>	<b>Location</b>	<b>Depth Range (MD ft)**</b>
<b>Groundwater Monitoring</b>				
Groundwater Sampling	At least one year prior to injection Quarterly	Biannual (twice/yr)	USDW1 OBS1 ACZ1 12 stations TBD	Varying
Isotope Analysis	Biannual (twice/yr)	Annually	USDW1 OBS1 ACZ1	Varying
<b>Injection Well Monitoring</b>				
Injection Pressure	NA	Continuous Continuous	CCS1 CCS1	Surface Above Packer
Injection Temperature	NA	Continuous	CCS1	Surface Above Packer
Injection Rate	NA	Continuous	CCS1	Surface
Injection Volume (Calculated)	NA	Continuous	CCS1	Injection Zone
Annular Pressure	NA	Continuous	CCS1	Surface
Annular Fluid Volume	NA	Daily	CCS1	Surface
<b>Mechanical Integrity Testing</b>				
MIT (Part I)	Once Once	Annually Annually	CCS1 OBS1	Surface Surface
FOT	Once	Every 5 years	CCS1	TBD
MIT (Part II)	Once Once	Annually Annually	CCS1 OBS1 (temp log only)	TBD TBD
Emergency Shut-down System Test	NA	Annually	CCS1	Surface
<b>Pressure Monitoring</b>				
Annular Pressure	NA	Daily	CCS1 OBS1	Surface Surface
Wellhead Pressure	NA	Continuous	ACZ1	Surface
Downhole Pressure	NA	Continuous	CCS1	TBD

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency*	Location	Depth Range (MD ft)**
			OBS1	TBD
<b>CO<sub>2</sub> Stream Analysis</b>				
CO <sub>2</sub> Stream Analysis	Once	Quarterly	CO <sub>2</sub> Delivery Pipeline	Surface
Corrosion Coupon Analysis	NA	Quarterly	Surface	Surface
<b>Plume Verification Monitoring</b>				
Pressure – Temperature Sensors	3 months prior to injection			
	Continuous	Continuous	CCS1	Above Packer (TBD)
	Continuous	Continuous	OBS1***	Injection Zone (TBD)
PNL	Once	Annually	CCS1	ACZ Monitoring Interval, Confining Zone, Injection Zone
	Once	Annually	OBS1	
Microseismic Monitoring	6 months prior to injection	Continuous	Minimum 5 Surface Stations	Confining Layer, Injection Zone, Precambrian Basement
Time-lapse 3D Surface Seismic Data	Once	Every 5 years	Area sufficient to image an 8.97 mi <sup>2</sup> plume	Imaging of CO <sub>2</sub> plume and overburden
*Minimum frequency ** To be confirmed after well is drilled ***Temperature data will not be collected				

## 1.5 Quality Assurance Procedures

Data quality assurance and surveillance protocols adopted by the project have been designed to facilitate compliance with the requirements specified in 40 CFR 146.90 (k). Quality Assurance (QA) requirements for direct measurements within the injection zone, above the confining zone, and within the shallow USDW aquifer are described in (Attachment 11: QASP, 2022). These measurements will be performed based on best industry practices and the QA protocols recommended by the service contractors selected to perform the work.

## 1.6 Reporting Procedures

Cardinal Ethanol will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91. Reports will be submitted every 6 months commencing from the date CO<sub>2</sub> injection operations commence.

## **2 Carbon Dioxide Stream Analysis (40 CFR 146.90 (a))**

The project will analyze the CO<sub>2</sub> stream during the injection phase of the project to provide data representative of its chemical characteristics and to meet the requirements of 40 CFR 146.90 (a).

This section describes the measurements and sampling methodologies that will be used to monitor the chemical characteristics of the CO<sub>2</sub> injection stream. Additional details on technical standards, QA/QC policy, sample collection and storage policies, and analytical methods are provided in the QASP.

### **2.1 Sampling Location and Frequency**

Prior to the start of the injection phase, the CO<sub>2</sub> stream will be sampled for analysis during regular plant operations in order to obtain representative CO<sub>2</sub> samples that will serve as a baseline dataset. Once the injection phase commences, samples of the CO<sub>2</sub> injection stream will be regularly collected from the CO<sub>2</sub> delivery pipeline for analysis.

Based on the nature of the ethanol fermentation process, the CO<sub>2</sub> stream produced is anticipated to be of high purity. Even so, after fermentation, the CO<sub>2</sub> stream will pass through scrubbers and filtration units prior to entering the compressor and the pipeline.

It is anticipated that quarterly sampling of the CO<sub>2</sub> injection stream will be sufficient to accurately track the composition of the stream. The regular samples will be taken on quarterly intervals.

Section 4.5 of the QASP document details the quality control mechanisms and activities to be performed should there be a statistically significant variance in an analyte measurement.

### **2.2 Analytical Parameters**

Samples of the injection stream will be collected for chemical analysis to provide data representative of its characteristics. Based on data from historic sampling of the off-gas stream from the ethanol plant, the samples will be analyzed for CO<sub>2</sub> purity, total hydrocarbons as methane carbon monoxide (CO), nitrogen oxides (NO<sub>x</sub>), nitrogen (N<sub>2</sub>), oxygen (O<sub>2</sub>), methane, hydrogen sulfide (H<sub>2</sub>S), sulphur dioxide (SO<sub>2</sub>), acetaldehyde (AA), and ethanol.

Baseline samples of the “injection stream” will be collected prior to the start of injection and the species included for analysis may be expanded depending on the results of those analyses. Gas concentration analyses will be done by a contracted third-party lab. The lab will specialize in gas analyses and routinely perform specialized analyses on CO<sub>2</sub> for industrial clients. Samples of the CO<sub>2</sub> stream will be collected on a quarterly basis for chemical analysis.

### **2.3 Sampling Method – CO<sub>2</sub> Injection Stream Gases**

Gas samples of the CO<sub>2</sub> stream will be obtained to analyze the components present in the injection stream. Samples of the CO<sub>2</sub> stream will be collected at a location in the system where the material is representative of the material injected (i.e., between the compression system and CCS1), using a 1/4-inch sampling port in the flowline. Fittings will be consistent with those used by the contracted third-party laboratory who will be performing the analysis will be used.

The CO<sub>2</sub> stream will flow from the pipeline through an open ball valve, through a pressure reducer (regulator), and into the cylinder. The pressure regulator will reduce the pressure of the CO<sub>2</sub> stream to approximately 250 pound-force per square inch (psi) to ensure the CO<sub>2</sub> is in a gaseous state rather than a super-critical liquid.

Figure 4 provides an example of the sampling procedures used by Atlantic Analytical Company. Cylinders will be purged with sample gas (i.e., CO<sub>2</sub>) at least five times prior to sample collection to remove laboratory-added helium gas and ensure a representative sample. The QASP (Attachment 11: QASP, 2022) contains more information on sampling methods.

<p><b>Introduction</b></p> <p>Atlantic Analytical Laboratory (AAL) provides pre-cleaned and conditioned stainless steel and sulfur-inerted sampling cylinders as a convenience to our customers. Rental cylinders are available in a variety of sizes, including 75cc, 300cc, 500cc, and 1 liter. All cylinders are DOT rated for 1,800 psig service, and are equipped with a burst-disc type relief valve set to approximately this pressure. All cylinders are dual ended, with 1/4" NPT valve port fittings. Cylinders are normally shipped with approximately 10 psig UHP grade helium backfill gas to prevent atmospheric contamination during shipment. Cylinders can be shipped under vacuum upon request.</p> <p><b>Safety</b></p> <p>Before sampling, review all MSDS information related to the gases present. Always wear safety glasses, protective gloves, and other necessary safety equipment. Sampling cylinders are only to be used by personnel trained in handling pressurized gases. For safety, always assume any cylinder or gas line contains the maximum amount of pressure possible in the system. Whenever possible, ensure that the sampling cylinder outlet port is attached to an appropriate vent line to avoid a potentially hazardous buildup of the gas being sampled, especially for oxygen and flammable gases. Refer to the back of this page for a diagram of a typical sampling setup.</p> <ul style="list-style-type: none"><li>➤ DO NOT sample toxic, corrosive, pyrophoric, or extremely reactive gases with these cylinders.</li><li>➤ DO NOT sample cryogenic or liquefied gases using these instructions; instead, refer to separate instructions available from AAL for proper sampling techniques for these gases.</li><li>➤ DO NOT EXCEED the MAXIMUM 1,800 PSIG fill pressure. If the relief valve burst disc ruptures, the cylinder cannot be used for sampling - return to AAL immediately for repairs, cleaning, and recertification.</li></ul> <p><b>Equipment</b></p> <p>Sampling cylinder, 1/4" NPT brass end cap, 1/4" NPT brass plug, ID tag.</p> <p><b>Sampling Procedure</b></p> <ol style="list-style-type: none"><li>1) Remove the brass cylinder end cap and plug and store them in a clean, secure location.</li><li>2) Loosely connect the inlet valve of the sampling cylinder to the gas source valve.</li><li>3) Carefully open the gas source valve and purge the connecting fittings of air - then tighten these fittings. Keep the gas source valve open until step 11.</li><li>4) Carefully open the cylinder inlet valve to allow the sample gas to fill the cylinder.</li><li>5) Close the cylinder inlet valve. Do not over tighten, as this may damage the valve seat and cause leakage.</li><li>6) Open the cylinder outlet valve, and allow a majority the cylinder gas to vent. DO NOT blow down completely to atmospheric pressure, as this may cause outside contaminants to diffuse into the cylinder.</li><li>7) Close the cylinder outlet valve.</li><li>8) Repeat steps 4 - 7 a minimum of 5 times to ensure the cylinder has been purged of all fill gas and conditioned with the sample gas.</li><li>9) Open the cylinder inlet valve and partially open the cylinder outlet valve to allow the sample gas to flow through the cylinder for at least 2 minutes.</li><li>10) Close the cylinder outlet valve and wait at least 30 seconds for the cylinder to fully pressurize.</li><li>11) Close both the cylinder inlet and gas source valves - then carefully disconnect the cylinder. Beware of excess gas pressure trapped between the two valves which may release suddenly when disconnecting the cylinder.</li><li>12) Apply new teflon tape to the NPT threads on the inlet valve of the cylinder and the brass outlet plug and securely cap both ends of the cylinder. DO NOT over tighten fittings or thread damage may result.</li><li>13) Record all sample data on the cylinder ID tag - please do not affix labels to the cylinder body.</li><li>14) Package the cylinder in a DOT/IATA approved shipping box or container and insert a completed AAL "Analytical Testing Request" form. Follow all applicable shipping regulations including affixing the proper sample UN designation, shipping name, hazard labels, and identification of the sample contents on all courier paperwork.</li><li>15) Ship the sample to AAL via an express air (if eligible) or qualified ground courier as soon as possible.</li></ol>
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Figure 4: Atlantic Analytical Laboratory gas sampling instruction sheet (Atlantic Analytical Laboratory, 2022)

## 2.4 Laboratory to be Used/Chain of Custody and Analysis Procedures

A contracted third-party laboratory will analyze the CO<sub>2</sub> stream samples. The lab will specialize in gas analyses and routinely perform specialized analyses on CO<sub>2</sub> for industrial clients. The contracted laboratory will follow standard sample handling and chain-of custody guidance (EPA 540-R-09-03, or equivalent).

The relevant QASP sections detail the following (Attachment 11: QASP, 2022):

- Sections B.2.f: Laboratory to be used and quality
- Sections B.2.e: Chain of custody
- Sections A.4.a: Analysis procedures

## 3 Continuous Recording of Operational Parameters

The project will install and use continuous recording devices to monitor injection pressure; injection rate (and volume [calculated]); the pressure on the annulus; the annulus fluid volume added; and the temperature of the CO<sub>2</sub> stream, as required at 40 CFR 146.88 (e)(1), 146.89 (b), and 146.90 (b). The details are described in the following sections.

### 3.1 Monitoring Location and Frequency

The project will perform the activities identified in Table 6 to monitor operational parameters and verify internal mechanical integrity of CCS1. All monitoring will take place at the locations and frequencies shown in Table 6. All of the data recorded on a continuous basis will be connected to the main facility through a SCADA system.

**Table 6: Sampling devices, locations, and frequencies for continuous monitoring.**

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Wellhead Injection Pressure	Pressure Gauge	Wellhead	Every 10 sec.	Every 10 sec.
Formation Injection Pressure	Pressure Gauge	Downhole Gauge	Every 10 sec.	Every 10 sec.
Wellhead Injection Temperature	Thermocouple	Wellhead	Every 10 sec	Every 10 sec.
Formation Temperature	Temperature Sensor	Above Packer Depth TBD	Every 10 sec.	Every 10 sec.
Injection rate	Coriolis Meter	Wellhead	Every 10 sec.	Every 10 sec.
		Booster Pump	Every 10 sec.	Every 10 sec.
Annular pressure	Pressure Gauge	Wellhead	Every 10 sec	Every 10 sec.
Annulus fluid volume	Volume	Wellhead	Every 1 min.	Every 1 min
<p>See Notes next page also:</p> <ul style="list-style-type: none"> <li>• Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.</li> <li>• Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.</li> </ul>				

Note that all calibration standards, methods of conformance, precision, and tolerance parameters are provided for the devices listed in the QASP (Attachment 11: QASP, 2022).

### **3.2 Monitoring Details**

#### **3.2.1 Continuous Recording of Injection Pressure**

The CO<sub>2</sub> injection pressure will be monitored on a continuous basis at the wellhead to ensure that injection pressures do not exceed the calculated maximum allowable injection pressure (MAIP), determined, in part, by using 90% of the fracture pressure of the injection zone per 40 CFR 146.88 (a). If the injection pressure exceeds 90% of the injection zone fracture pressure at any point, then the injection process will be automatically shutdown per the Well Operations Plan (Attachment 6: Well Operations, 2022).

Based on current information, 90% fracture pressure gradient is expected to be 0.75 psi/ft that results in a maximum allowable bottomhole flowing pressure (BHFP) of 2,369 psi at a depth of 3,159 feet, which is the projected top of the Mt. Simon Sandstone (Attachment 2: AoR and Corrective Action, 2022). This will be re-assessed with the data collected during the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022).

The BHFP has been calculated as approximately 2,050 psi during the first year of normal operations; however, it is anticipated to decline to approximately 1,700 psi after five years of injection.

Based on the calculations and detail provided in the Well Operation Program section of this application, the MAIP (at surface) is 2,048 psi. Pressure will be continuously monitored by an electronic pressure transducer to ensure that the MAIP is not exceeded during injection operations. This electronic pressure transducer will feed into the SCADA system.

As is noted in the Well Operations section, several assumptions have gone into the calculations for the MAIP. To assist with the proper hydrostatic gradient evaluations, permanent downhole gauges will be used. The data gathered from this sensor will help to calibrate the surface pressure readings. The current plan is to use these gauges for calibration purposes until sufficient hydrostatic data has been collected. It is noted that these gauges are not considered to be a part of the routine testing and monitoring program, but for gradient calibration and model/simulation verification to be used as part of the testing and monitoring program.

Any anomalies outside of the normal operating specifications may indicate that an issue has occurred within the well, such as a loss of mechanical integrity or blockage in the tubing or may be caused by a change in injection flowrate. Anomalous pressure measurements would trigger the need for further investigation of the cause of the change (40 CFR 146.89 (b)). The wellhead and downhole injection pressures will also be used to calibrate the computational modeling throughout the injection phase and PISC phases of the project.

#### **3.2.2 Continuous Recording of Injection Mass Flow Rate**

The mass flow rate of CO<sub>2</sub> injected into the well will be measured by a mass flow meter. This flow meter will be placed in the CO<sub>2</sub> delivery line near the well. A second mass flow meter will be located in the CO<sub>2</sub> delivery line just downstream of the final compressor, and the two flow meters will be used together to monitor leakage in the delivery line between the compressor and the well.

The meters will have an analog output. The flow meters will be connected to the SCADA system for continuous monitoring and control of the CO<sub>2</sub> injection rate into the well. Using two flow meters will allow confirmation of accurate flow measurements. The mass flow meters will be calibrated at the frequency recommended by the manufacturer.

### 3.2.3 Injection Volume

The injection volume into the reservoir will be calculated on a continuous basis based on the injection mass and the pressure and temperature conditions in the storage formation. The volume that is calculated will be used in the computational models to determine storage formation capacity and flow.

### 3.2.4 Continuous Recording of Annular Pressure

As discussed in the Well Operations Plan, the pressure on the annulus between the injection tubing and the long-string casing will be measured by an electronic pressure transducer with analog output that is mounted on the wing valve/annular fluid line connected to the wellhead of CCS1 (Attachment 6: Well Operations, 2022). The transmitter will be connected to the well control system and the SCADA system to regulate the annular pressure.

Annular pressures are expected to vary during normal operations due to atmospheric and CO<sub>2</sub> stream temperature fluctuations; however, the well control system will be designed to maintain the annular pressure between -5 and 1,500 psi (Attachment 6: Well Operations, 2022).

In particular, the annular pressure is expected to fluctuate during start-up and shut-in operations as the tubing naturally expands and contracts in response pressure and temperature changes related to CO<sub>2</sub> flow, or lack thereof, in the tubing. Sudden changes in the annular pressure during routine injection operations are a sign of potential tubing or tubing packer integrity issues that will trigger further investigation through mechanical integrity testing.

### 3.2.5 Continuous Recording of Annulus Fluid Volume

As discussed in the Well Operations Plan, the volume of the annulus fluid between the injection tubing and the long-string casing will be measured using the accumulator levels and the brine reservoir level on the well control system (Attachment 6: Well Operations, 2022). The accumulator and brine reservoir levels will be measured using a level transmitter. The transmitters will be connected to the well control system and to the SCADA system.

Similar to the annular pressure, the annular fluid volume is expected to fluctuate as atmospheric and injection stream temperatures change. These changes are expected to be most dramatic during start-up and shut down operations. A significant change in the fluid volume in the accumulator or brine reservoir (i.e., fluid is being pumped from the reservoir to the annulus or fluid being pushed out of the annular space) during routine injection operations may be an indication of well integrity problems, as the fluid volumes would normally remain relatively constant, and will require further investigation.

### 3.2.6 Continuous Recording of CO<sub>2</sub> Stream Temperature

The temperature of the CO<sub>2</sub> injection stream will be continuously measured by an electronic thermocouple. The thermocouple will be mounted in a temperature probe in the CO<sub>2</sub> line at a location close to the pressure transmitter near the wellhead. The transmitter will be electronically connected to the SCADA system.

### 3.2.7 Bottomhole Pressure and Temperature

Bottomhole pressure and temperature will be monitored prior to and during the injection phase of the project. These data will be used to assist with the calibration of the wellhead pressure measurements to determine the response of the formation to the injected CO<sub>2</sub>.

The downhole pressure gauge will be set at the bottom of the injection string, just above the packer, at approximately 3,160 ft and will be programmed to continuously record the pressure and transmit it to surface.

After the wellhead/ injection zone pressure relationship has been defined, the wellhead pressure measurement will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure as per 40 CFR 146.88 (a). The downhole pressure and temperature data will also be used to calibrate the computational models.

## 4 Corrosion Monitoring (40 CFR 146.90 (c))

To meet the requirements of 40 CFR 146.90 (c), the project will monitor well materials and components during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance (Table 7). This section discusses the measures that will be taken to monitor the corrosion of well materials used in the casing and tubing. For Class VI injection wells, corrosion monitoring of the well materials is required on a quarterly basis (40 CFR 146.90 (c)).

### 4.1 Monitoring Location and Frequency

The corrosion coupons will be retrieved and analyzed every three months after the date that injection commences. Once injection operations have stabilized, it is not expected that there will be large fluctuations in injection volumes, so there are no plans to monitor the coupons based on injection volumes. If the coupons show evidence of corrosion, CCS1 can be assessed for signs of corrosion using commercially available logging or other inspection tools.

### 4.2 Sample Description

The coupons will be made from the same materials as the long string casing and tubing (Table 7). Prior to placement of the corrosion coupons in the CO<sub>2</sub> stream, they will be weighed and measured for thickness, width, and length as a baseline measurement.

**Table 7: List of equipment coupon with material of construction.**

Equipment Coupon	Material of Construction
Long String Casing	13Cr80 Steel Alloy and Standard Carbon Steel
Injection String	Standard Carbon Steel with TK-15XT Coating (Tuboscope)
Pipeline	Stainless Steel
Wellhead	Xylan coated iron
Packer	Nickel coated steel, nitrile

### 4.3 Monitoring Details

Corrosion monitoring of well materials will be conducted using coupons placed in the CO<sub>2</sub> pipeline (Figure 5). The coupons will be made of the same materials that are listed in the table above. An example of one such coupon is provided in Figure 6. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ASTM) G1-03: Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM, 2017). This method measures the corrosivity of steel to both aqueous and non-aqueous liquid wastes.

Upon removal, coupons will be inspected visually for evidence of corrosion, which may include pitting, cracking, and loss of mass or thickness. The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed and compared to the baseline measurements. Corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

If the coupons show evidence of corrosion, CCS1 can be assessed for signs of corrosion using commercially available logging or other inspection tools. The frequency of running these inspection logs will be contingent on the corrosion data from the coupon monitoring program.

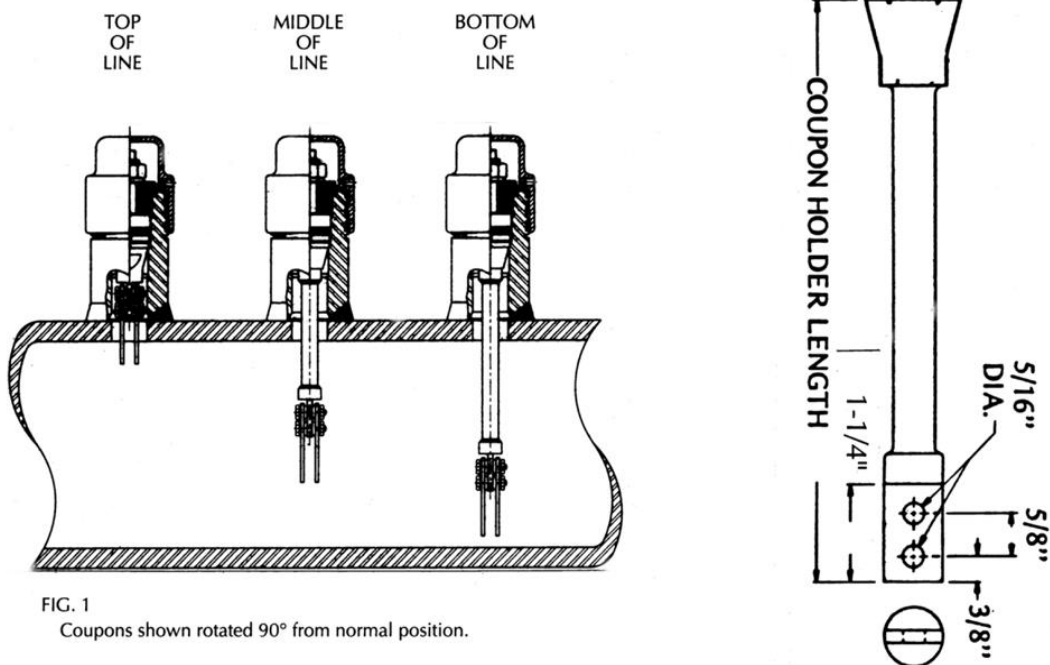
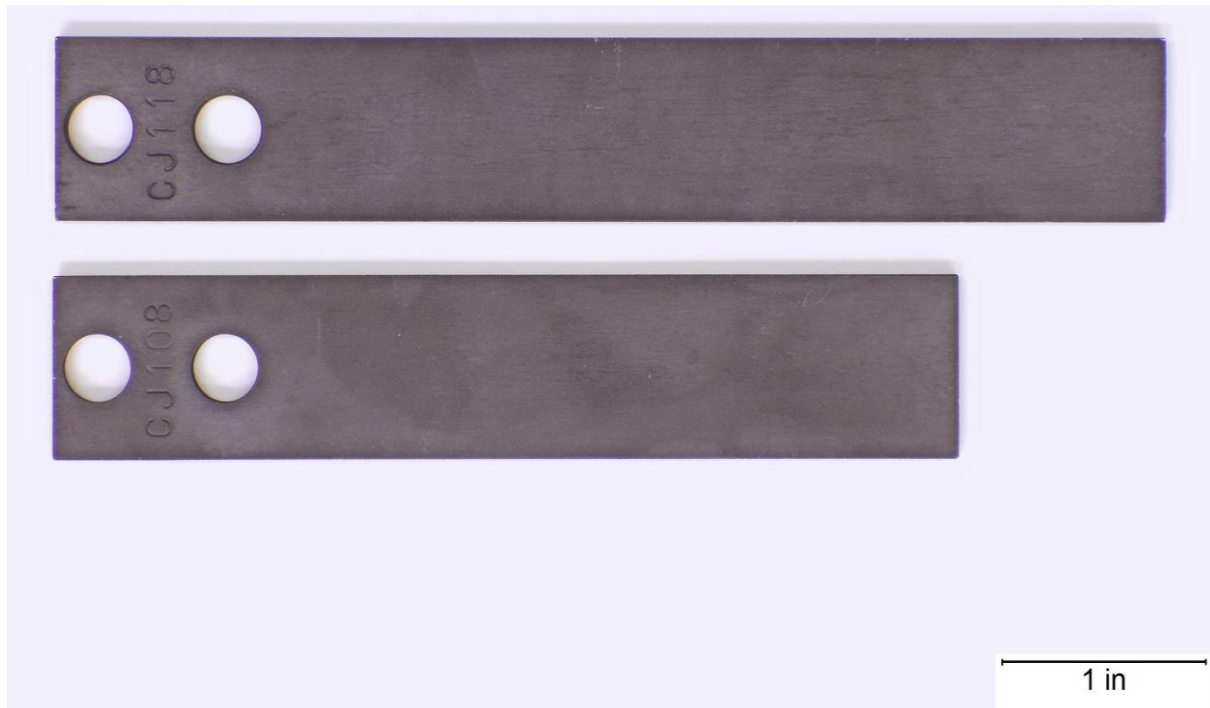


Figure 5: Corrosion coupon illustration in pipeline (Cosasco, 2022)



**Figure 6: Type of corrosion coupons to be used for corrosion monitoring (Cosasco, 2021)**

## 5 Above Confining Zone Monitoring (40 CFR 146.90 (d))

The project will monitor groundwater quality and geochemical conditions above the confining zone during the operational period to meet the requirements of 40 CFR 146.90 (d).

### 5.1 Monitoring Location and Frequency

Table 8 shows the proposed deep ACZ monitoring zone, lowermost USDW, and shallow groundwater monitoring methods, depths, and frequencies. The project will aim to acquire a minimum of one year of shallow groundwater data before injection operations begin. It is anticipated that USDW1 and ACZ1 will be drilled in Q1 2024. Fluid samples will be taken for analysis from these wells twice prior to the start of injection operations.

**Table 8: Schedule for monitoring of pressure, aqueous geochemistry, and stable isotope analysis for the ACZ, USDW1,**

Designated Well(s)	Target Formation	Monitoring Activity	Baseline Frequency	(Minimum) Injection Phase Frequency
Existing Wells TBD	Shallow Groundwater Wells	Aqueous Geochemistry	Quarterly	Biannual*
		Stable Isotopes	Biannual*	If required
USDW1	Lowermost USDW	Aqueous Geochemistry	Biannual*	Biannual*
		Stable Isotopes	Biannual*	Biannual*
ACZ1	Knox Formation (TBD)	Wellhead Pressure	Continuous	Continuous (Every hour)
		Aqueous Geochemistry	Biannual*	Biannual*
		Stable Isotopes	Biannual*	Biannual*
*twice per year				

**and shallow groundwater monitoring wells during the pre-operational and injection phases of the project**

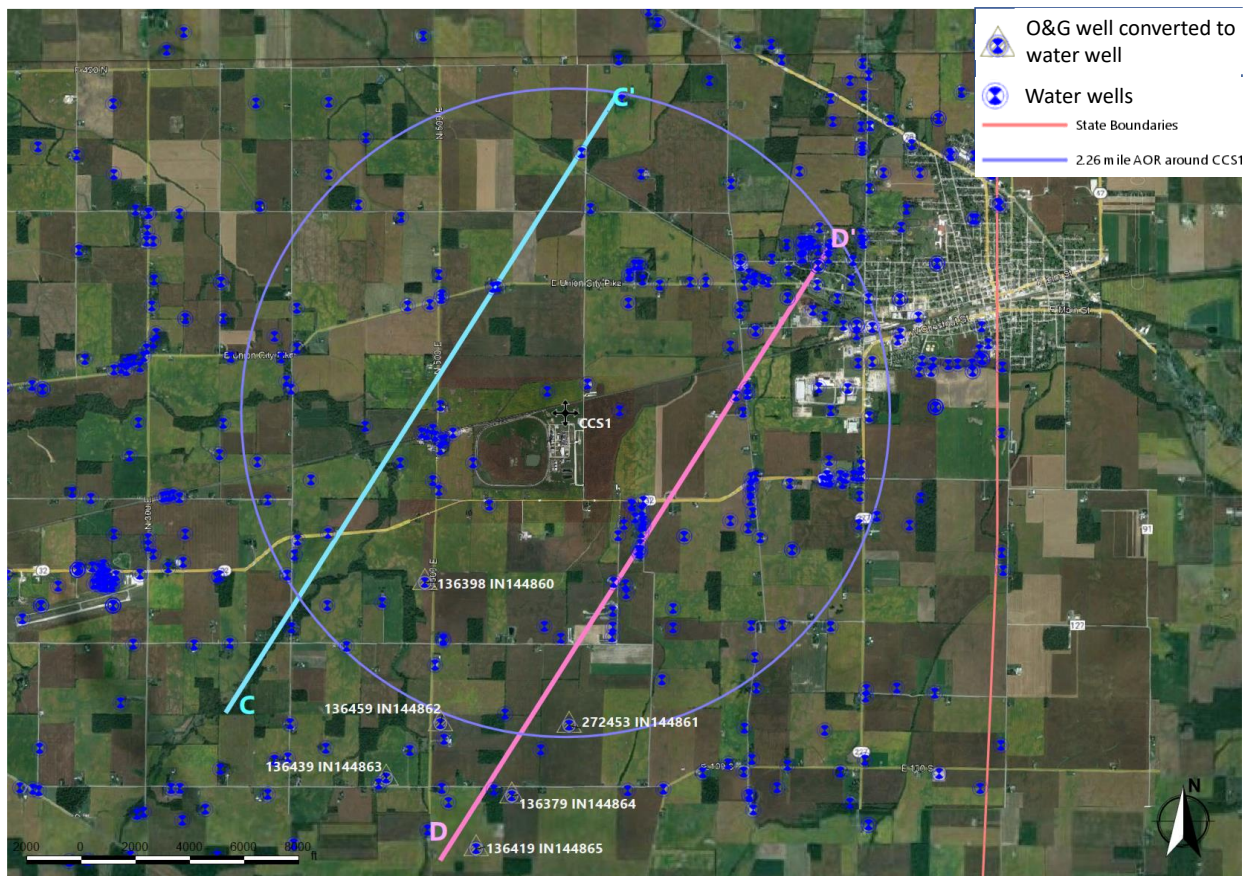
Given the thick and continuous nature of the Mt. Simon Sandstone, the highest risk of CO<sub>2</sub> or brine migration out of the injection zone is along the CCS1 and OBS1 wellbores that will penetrate the Eau Claire Formation. As such, ACZ1 will be drilled near CCS1 to help monitor for any CO<sub>2</sub> leakage or brine migration into the ACZ monitoring zone. As discussed in Section 2.4.7, the deepest ACZ saline formation is expected to be identified in the Knox Formation when the first well is drilled. Fluids from the deepest ACZ saline formation will be sampled twice prior to the start of CO<sub>2</sub> injection to characterize any natural variability in the fluids in the formation (Table 8).

Migration of CO<sub>2</sub> or brine into the ACZ saline formation will likely first be identified through pressure changes in the formation. An increasing pressure trend in the ACZ monitoring zone would suggest that leakage across the confining zone has occurred. While any increasing trend in pressure will be evaluated, an increase in pressure that deviates more than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid leakage out of the injection zone. Such a change in pressure would initiate more frequent fluid sampling and analysis for aqueous geochemistry from the ACZ monitoring zone as well as

additional external well integrity investigations in the CCS1 or OBS1. Pressures in the ACZ monitoring interval will be monitored at the wellhead.

The lowermost USDW is expected to be located at a depth of approximately 450 ft (BGS) based on local well data (Attachment 1: Narrative, 2022). USDW1 will be drilled relatively close to CCS1 to be able to properly monitor the fluids in the lowermost USDW.

Figure 7 shows the distribution of the groundwater wells within the AoR including the proposed location of USDW1. The shallow groundwater monitoring program will include approximately twelve existing groundwater wells that will be spatially distributed within the AoR (40 CFR 146.90 (d)). Baseline shallow groundwater samples will be collected from existing shallow groundwater wells within the AoR on a quarterly schedule starting in the third or fourth quarter of 2022 in order to characterize the seasonal variations in groundwater quality within the AoR (Table 8).



**Figure 7: Shallow groundwater wells within the AoR annotated in blue. Oil and gas wells that have been converted to water wells have been highlighted.**

The accumulation of CO<sub>2</sub> or brine in an overlying aquifer will likely result in changes to the following parameters:

- Aqueous geochemistry parameters such as pH and alkalinity
- Reaction of cements, mineral surface coatings, and clay particles with the CO<sub>2</sub> will liberate cations and anions into the aqueous phase
- Carbon isotopes can be used to differentiate between existing CO<sub>2</sub> sources within the AoR and the injected CO<sub>2</sub>

If anomalous changes in the aqueous geochemistry are observed in the ACZ monitoring interval or the lowermost USDW, new samples will be obtained from the affected formation to verify the changes. The frequency with which fluid samples are obtained from each of the zones for analysis will also be increased.

If the injected CO<sub>2</sub> has a unique isotopic signature from the existing isotopes in the ACZ monitoring interval or the lowermost USDW, a new round of samples will be collected for isotopic analysis from the affected formation. Anomalous changes may also trigger the need for additional well integrity testing in both CCS1 and OBS1 to ensure that no well integrity issues have developed since the last set of external mechanical integrity tests (Section 6.2). Stable isotopes from the shallow groundwater samples will only be analyzed if anomalies are found in the ACZ monitoring interval or lowermost USDW.

A combination of anomalous pressure, geochemical, and well integrity testing results may result in the decision to acquire a time-lapse surface seismic survey to determine the size of a potential leakage accumulation. Further details on any remedial or emergency response are detailed in the ERRP portion of this permit application (Attachment 10: ERRP, 2022).

## **5.2 Analytical Parameters**

Table 9 details the full suite of analytes that will be used to establish the baseline conditions from OBS1, ACZ1, USDW1, and the shallow groundwater monitoring wells. Once the project has established baseline conditions, it may reduce monitoring to a subset of analytes that are most likely to change as a result of interactions with CO<sub>2</sub>; however, no changes would be implemented without consultation with the UIC Program Director. During the injection phase of the project, fluids from these wells will be sampled biannually to identify any changes to parameters aqueous geochemistry or stable isotopes.

**Table 9: Summary of analytical and field parameters for groundwater samples**

<b>Parameters</b>	<b>Analytical Methods<sup>(1)</sup></b>
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Ti Ca, Fe, K, Mg, Na, and Si	ICP <sup>(2)</sup> -MS <sup>(3)</sup> , EPA Method 6020 ICP-OES <sup>(4)</sup> , EPA Method 6010B
Anions: Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0
Dissolved CO <sub>2</sub>	Coulometric Titration ASTM D513-11
Stable Isotopes of $\delta^{13}\text{C}$ Dissolved Inorganic Carbon (DIC)	Isotope Ratio Mass Spectrometry <sup>(5)</sup>
Total Dissolved Solids (TDS)	Gravimetry APHA 2540C
Water Density (field)	Oscillating Body Method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Conductivity/Resistivity (field)	APHA 2510
Temperature (field)	Thermocouple
Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director. Note 2: Inductivity Coupled Plasma Note 3: Mass Spectrometry Note 4: Optical Emission Spectrometry Note 5: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)	

Changes in these parameters during the injection phase of the project may provide an indication of CO<sub>2</sub> or brine movement above the confining layer. While pH and alkalinity may be indicators of CO<sub>2</sub> migration above the confining zone, the dissolved inorganic carbon analysis would provide direct evidence of CO<sub>2</sub> migration into these formations. The presence of Carbon-13 or stable isotopes of C (in dissolved inorganic carbon) may provide an indication of fluid or CO<sub>2</sub> migration into the ACZ monitoring zone and may also provide information about the origin of any migrating fluids.

The relative benefit of each analytical measurement will be evaluated throughout the design and initial injection testing phase of the project to identify the analytes best suited to meeting project monitoring objectives under site-specific conditions. If some analytical measurements are shown to be of limited use, they will be removed from the analyte list and not carried forward through the operational phases of the project. Any modification to the parameter list in

Table 9 will be made in consultation with the UIC Program Director.

Currently, there are no plans to use tracers during operations; however, as the monitoring plan is designed to be adaptive as project risks evolve over time and may be re-assessed at a later date.

### 5.3 Monitoring and Sampling Methods

Pressure in the ACZ monitoring zone will be monitored from the wellhead. The gauge will record and transmit data the SCADA system once every 10 seconds. The gauge will be installed on the wellhead at least three months prior to any injection to ensure that a sufficient baseline is established.

For ACZ fluid sampling, a bailer system will be used to collect the water samples. Prior to sample collection the well will be flushed to remove stagnant water from the well and ensure representative water is collected from the formation. The fluid removed from the well will be monitored for field parameters that are listed in Table 9. Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Preservation/preparation methods, container type, and holding times for the analyte classes are presented in the QASP section of this application.

### 5.4 Laboratory to be Used/Chain of Custody Procedures

The geochemical analyses and the isotopic analyses will be performed by contracted third-party laboratories that meet the standards and guidelines set forth in the QASP. Samples will be tracked using appropriately formatted chain-of-custody forms (Attachment 11: QASP, 2022).

## 6 Mechanical Integrity Testing

### 6.1 Internal Mechanical Integrity Testing

Internal (Part I) mechanical integrity testing (MIT) refers to the testing of the integrity of the seals within and between the: injection string, the long casing string, the packer, and the wellhead. The quality of these seals can be confirmed with an annulus pressure test (APT) and annular pressure monitoring. Both methods will be used during the injection phase of this project to monitor and confirm internal mechanical integrity. Table 10 presents the details for conducting the annular pressure MIT and the annular pressure monitoring.

Table 10: Internal mechanical integrity monitoring details

Testing/Monitoring Method	Frequency	Location of Monitoring	Parameters Measured
APT	After completion or workover Annually	CCS1 Wellhead OBS1 Wellhead	Pressure
Annular Pressure Monitoring	Continuous	CCS1 Wellhead OBS1 Wellhead	Pressure, temperature, annular fluid volume

In addition to performing an APT annually, an APT will be performed after the initial well completion. It is noted that the annulus will be filled with a non-corrosive fluid with some additives.

#### 6.1.1 Annulus Pressure Testing (40 CFR 146.89(a))

The APT will be performed annually to exhibit Part I mechanical integrity, or any time a component of the internal seals, detailed above, are broken or altered. The test will be performed consistent with approved and accepted guidance and regulations. This is consistent with CFR 146.89 (a). In addition, an APT will be performed following an emergency shut-in due to a high-high or low-low annulus alarm should the cause of the alarm not be easily correlated to a change in temperature.

The APT will then be performed by pressuring up the annulus after the well has reached thermal equilibrium. Once this has occurred, the annulus will be pressured up to 1,500 psi. A calibrated digital gauge will be installed on the annulus, and the pressure will be monitored for a period no less than 60-minutes.

The following procedure will be followed for all APTs that will be run.

1. Ensure well is in thermal equilibrium. Thermal equilibrium will be assumed under the following circumstances:
  - a. Injection has not occurred for approximately 24 hours, or sufficient data indicates the wellbore temperature is static. The scenario constitutes a static APT.
  - b. Injection is occurring at a constant rate ( $\pm 5\%$ ), often referred to as a dynamic APT.
2. Install calibrated digital gauge on the casing-tubing annulus. Note initial pressures.
3. Increase annulus pressure to 1,500 psi.
  - a. Ensure to note the fluid level in the system prior to increasing the annulus pressure.
4. Disconnect annulus system and ensure the annulus is isolated.
5. Monitor the annulus and tubing pressure for a period of one-hour, taking readings every 10-minutes.
6. Once the test has concluded, reconnect the annulus system.
7. Blow the pressure down to the normal operating pressure.
8. Note the fluid level in the system.

#### 6.1.2 Annulus Pressure Monitoring

In addition to the APT, the annular pressure will be continuously monitored throughout the operational period in conjunction with the annular pressure monitoring and control system to ensure internal mechanical integrity. Once injection operations commence, injection pressure, annular pressure, and annular fluid volumes will be monitored continuously in order to ensure that internal well integrity and proper annular pressure is maintained (Attachment 6: Well Operations, 2022).

If a change in the annular pressure or annular fluid volume indicates a change that was not a result of temperature or injection rate alteration, the cause of the change will be investigated (Attachment 6: Well Operations, 2022). Note that changes in the temperature of the injection stream can result in changes in the temperature of the annular space, leading to variations in

annular pressure. Initial investigations would likely look at correlations between the temperature of the injection stream and the variations in annular pressure.

## 6.2 External Mechanical Integrity Testing (40 CFR 146.90 (e))

The project will conduct external (Part II) MIT annually to meet the requirements of 146.89(c) and 146.90(e).

### 6.2.1 Testing Methodology and Frequency

External mechanical integrity refers to the absence of fluid movement through channels between the long casing string and the borehole or the intermediate casing string. Migration of fluids through this zone could result in contamination of USDWs; therefore, the external integrity of CCS1 and OBS1 will be confirmed throughout the injection phase of the project. Part II MIT activities will occur annually.

This project plans to use temperature and RAT logging to ensure Part II mechanical integrity. It is noted that the practice of running temperature and RAT logs in tandem to ensure Part II mechanical integrity is a generally accepted method used in Class I and II wells across multiple EPA regions.

Table 11 show the logs to be run to display Part II mechanical integrity, as well as the frequency with which they will be run and the depth range they will be run over.

**Table 11: External mechanical integrity tests**

Test	Well	Depth Range (MD ft)	Schedule
Temperature Log	CCS1	Surface to Well TD	Annually
	OBS1	Surface to Well TD	Annually
Radioactive Tracer Log	CCS1	500 feet above packer to Well TD	Annually

It is important to note that while PNL is not planned to be a direct method of displaying Part II mechanical integrity, it can be used to identify accumulations of CO<sub>2</sub> adjacent to the wellbore in intervals above the Mt. Simon Sandstone.

#### 6.2.1.1 Temperature Logging

Temperature logging is used to establish a temperature profile of the well and make year to year comparisons to determine if any unexpected variations are present. Each year, multiple temperature log runs will be made to monitor the temperature decay after injection has stopped.

Temperature logs will be run using the same tool assembly as is presented in the RAT logging Section (7.2.1.2). Following the conclusion of the RAT logging, the well will be shut-in and a baseline temperature log will be run as per the schedule in

Table 12. This will allow for four temperature curves to be plotted for each year that temperature logs will be performed. Temperature logs will be acquired from the bottom up.

**Table 12: Temperature logging schedule for well integrity**

<b>Temperature Logging Run</b>	<b>Time Increment from Shut-in (hrs)</b>
Baseline	Shut-in
Second	1
Third	3
Fourth	6

#### 6.2.1.2 Radioactive Tracer Logging

The primary purpose of RAT logging is to verify the absence of pathways along the wellbore for the upward migration of injection zone fluids. RAT logging will be performed in accordance with federal and state guidance, if it is available.

RAT logs will be run while fluid is actively being injected into the well. As such, pressure, temperature, and rate data will be collected as part of the logging activities and reporting.

A RAT logging tool will be run on the same string as a gamma ray (GR), casing collar locator (CCL), and temperature tool. A summary of the general testing events is provided below.

1. Run baseline GR log across the zone of interest.
2. Run 5-minute statistical (stat) checks on the tool. These stat checks should be run in an area with a known low GR signature, and in an area with a known, higher GR signature. This check will help to ensure the tool is operating properly.
3. Run tracer chase sequence. A tracer will be ejected at least 300 feet above the packer, after which the tool will chase the tracer down the injection string and into the cased-hole interval by performing successive downward passes through the well. Multiple passes will be made over the perforated interval to ensure that all the tracer has exited the tubing and passed into the Mt. Simon Sandstone
4. Run time-drive sequence. A tracer will be ejected at least 300 feet above the packer. After which the tool will be move to just above the packer. The tool will record the GR measurements at the set depth for a minimum of 30-minutes. During this time, the tracer will be observed passing the tool and never have any upward movement.
5. Run final GR log across the zone of interest.

This sequence of logs will allow for investigation into any potential upward pathways for fluid migration out of the injection interval present during injection.

#### 6.2.2 Testing Details

The data from each annual logging event will be compared to the baseline log to determine if there are any inconsistencies between the logs. If inconsistencies appear, the cause of the deviations will be determined, and additional logs will be performed over the entire depth of the well to substantiate results of the MIT logging.

## **7 Pressure Fall-Off Testing (40 CFR 146.90 (f))**

The project will perform pressure fall-off tests (FOT) during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

Pressure fall-off testing involves the measurement and analysis of pressure data from a well after it has been shut-in. FOT tests provide the following information:

- Confirmation of reservoir properties such as flow capacity (kh), which is used to derive average permeability.
- Formation damage (skin) near the well bore, which can be used to diagnose the need for well remediation
- Changes in injection zone performance over time, such as long-term pressure build-up in the injection zone
- Average injection zone pressure that can be used to calibrate computational modeling predictions of injection zone pressure to verify that the operation is responding as modeled/predicted

### **7.1 Testing Location and Frequency**

Fall-off tests will be run every five years on CCS1 during injection operations. An initial FOT will be run as part of the pre-operational testing to be performed on the well. The permanent downhole pressure gauges set above the packer will be used for the FOT.

Surface monitoring equipment will be used to monitor injection data for the test.

### **7.2 Testing Details**

To begin the FOT, a constant rate injection period will be used for a minimum period of 24-hours. The rate will be kept within  $\pm 5\%$  during this period and will be at a rate that is representative of the injection rate for normal operations.

Following this constant rate injection period, injection will cease, and the well will be shut-in at the wellhead. Pressure will be monitored for a period to be no longer than the constant rate injection period. Following the shut-in period, the well will be restarted, and routine injection operations will resume.

Surface monitoring equipment will be used to record the injection data. This test can be performed as a function of routine injection operations and will prevent any additional shut-in of the well other than what is necessary for the test.

The downhole pressure data will be collected, and pressure transient analysis (PTA) will be performed on the data. Analysis of the test data will be completed using PTA techniques that are consistent with guidance for conducting pressure fall-off tests.

## **8 Carbon Dioxide Plume and Pressure Front Tracking (40 CFR 146.90 (g))**

The project will employ direct and indirect methods to track the extent of the CO<sub>2</sub> plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90 (g).

## 8.1 Plume Monitoring Location and Frequency

Table 13 presents the methods that the project will use to monitor the position of the CO<sub>2</sub> plume; this includes the activities, locations, and frequencies the project will employ. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Quality assurance procedures for these methods are presented in (Attachment 11: QASP, 2022).

**Table 13: CO<sub>2</sub> plume monitoring activities**

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
<b>DIRECT PLUME MONITORING</b>				
Mt. Simon Sandstone	Fluid Sampling	OBS1	Exact depth TBD	Twice/year until CO <sub>2</sub> breakthrough
	Isotope Analysis	OBS1	Exact depth TBD	Once/year until CO <sub>2</sub> breakthrough
	PNL	CCS1 OBS1	ACZ monitoring interval to TD	Once/year until fully saturated with CO <sub>2</sub> Once/year
	Downhole Pressure	CCS1 OBS1	TBD (above packer) TBD	Continuous
	Downhole Temperature	CCS1	Downhole, just above the packer	Continuous
<b>INDIRECT PLUME MONITORING</b>				
Entire Interval	Time-lapse 3D Surface Seismic Data	Over project AoR	Area sufficient to image an 8.97 mi <sup>2</sup> plume	Every 5-10 years, as appropriate

Fluid samples will be obtained for analysis from the Mt. Simon Sandstone during the initial well completion and pre-operational testing program (Attachment 5: Pre-Op Testing Program, 2022). The final sampling interval in the Mt. Simon Sandstone will be determined after the well has been drilled and the well logs have been analyzed. The CO<sub>2</sub> plume is expected to intersect OBS1 approximately five years after injection commences. Once free phase CO<sub>2</sub> breaks through at OBS1, the project will stop taking fluid samples from the Mt Simon Sandstone.

Baseline PNL logs will be acquired in CCS1, OBS1 and ACZ1 prior to the start of injection operations. Once injection starts, PNL logs will be acquired in CCS1 and OBS1 once each year. A baseline 3D surface seismic survey will be acquired in Q4 2022 or Q1 2023. Subsequent time-lapse 3D surface seismic surveys will be acquired every five to ten years after injection operations commence.

At this time, no continuous CO<sub>2</sub> plume monitoring has been planned for the project. Likewise, no phased or adaptive monitoring has been planned for the project in terms of expanding the monitoring network. However, if during the reassessment of the AoR during the injection phase

of the project, the AoR is shown to have grown, the Testing and Monitoring Plan will be reassessed (Attachment 2: AoR and Corrective Action, 2022).

## **8.2 Plume Monitoring Details**

As CO<sub>2</sub> is injected into the Mt. Simon Sandstone, the geochemistry of the fluids and isotopes in the formation are expected to change. Geochemical modelling will be used to predict the geochemical changes to the Mt. Simon Sandstone fluids once data from the pre-operational testing program has been collected (Attachment 5: Pre-Op Testing Program, 2022).

The results of the geochemical and isotope analysis will be delivered in the form of lab reports. Section 6.3 of this document details the sampling procedures that will be used. Table 9 summarizes the analytical and field parameters for the fluid sampling. Details on the methods, containers, and preparation methods for the fluid sampling can be found in (Attachment 11: QASP, 2022). The project will stop taking fluid samples from the Mt. Simon Sandstone once free phase CO<sub>2</sub> is encountered at the sampling ports.

The PNL logs will be received as LAS files and interpreted products that can be imported into the static model. This logging data will be used to monitor the distribution and saturation of CO<sub>2</sub> adjacent to the wellbores in CCS1 and OBS1. The logs will be acquired through the Mt. Simon Sandstone as well to confirm the absence of CO<sub>2</sub> accumulations along the wellbore above the confining zone in the ACZ monitoring zone. Technical details on the logging tools can be found in the (Attachment 11: QASP, 2022).

Surface seismic data is delivered in a variety of formats including acquisition and processing reports and SEG-Y data files from a variety of points in the processing flow. In the context of time-lapse analysis, an assessment will be provided on the differences between the baseline and time-lapse surveys as well as data files that can be incorporated into the static model. Once a data processing company is selected for the surface seismic processing, detailed information can be provided on their processing flows; however, it is expected that the company will use industry standard processing flows for noise attenuation, demultiple, pre-stack migration, and time-lapse analysis. The injection of CO<sub>2</sub> and expansion of the plume is expected to change the acoustic impedance and travel times of the seismic waves through the Mt. Simon Sandstone, and these changes will be used to track CO<sub>2</sub> plume development over time. The time-lapse surface seismic data will also be monitored for changes that may suggest that CO<sub>2</sub> has migrated past the confining zone and into the overlying formation(s).

The results of the geochemical and isotope analysis, PNL, and time-lapse 3D surface seismic data will all be integrated to develop a comprehensive understanding of the CO<sub>2</sub> plume development over time. The logging and time-lapse 3D surface seismic data can be incorporated into the static model for comparison to the computational modelling predictions at different points in time. The data can be used to constrain the computational modelling results and produce better plume predictions over the course of the project. The logging data will be used to calibrate the computational modelling on a yearly basis and provide information on the vertical and horizontal plume development. It will also provide more detailed and direct measurement of CO<sub>2</sub> saturations than indirect seismic methods. The time-lapse 3D surface seismic data will be used to update the models every five to ten years. If the CO<sub>2</sub> plume monitoring data diverges significantly from the modelled plume predictions, it may result in a reassessment of the AoR (Attachment 2: AoR and Corrective Action, 2022).

### 8.3 Pressure-Front Monitoring Location and Frequency

Table 14 presents the methods that the project will use to monitor the position of the pressure front; this includes the activities, locations, and frequencies the project will employ. Quality assurance procedures for these methods have been presented in the QASP (Attachment 11: QASP, 2022).

**Table 14: Pressure plume monitoring activities**

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
<b>Direct Pressure-Front Monitoring</b>				
Mt. Simon Sandstone	Pressure Monitoring	CCS1 OBS1	Mt. Simon Sandstone Interval	Continuous
<b>Indirect Pressure-Front Monitoring</b>				
Eau Claire Formation Mt. Simon Sandstone	Microseismic Monitoring	Minimum of five (5) Surface Stations	Events within an 8 mi radius of CCS1	Continuous

The pressure/temperature sensors will be programmed to measure and record pressure and temperature readings every 10 sec. The final monitoring interval will be determined after CCS1 has been drilled and the well logs have been analyzed (Attachment 5: Pre-Op Testing Program, 2022). Ideally, the project will start recording pressures in the Mt. Simon Sandstone the quarter before injection operations commence.

Microseismic data will also be recorded on a continuous basis. This data will be sent to a cloud-based service via a cellular connection for data processing and archive. Baseline microseismic data will be acquired for four to six months prior to the start in injection operations.

No phased or adaptive monitoring has been planned for the project in terms of expanding the monitoring network. However, if during the reassessment of the AoR during the injection phase of the project, the AoR is shown to have grown, the Testing and Monitoring Plan will be reassessed (Attachment 2: AoR and Corrective Action, 2022).

### 8.4 Pressure-Front Monitoring Details

Pressure/temperature sensors will be placed on the tubing string of CCS1, OBS1, and ACZ1 to monitor the pressures. The gauges will collect and transmit data to surface continuously. Refer to the QASP for technical information on the potential pressure/temperature gauges (Attachment 11: QASP, 2022).

The pressure/temperature data will be stored as time stamped data pairs. It is expected that the pressure in the injection zone will begin to increase when injection operations begin. This data will be used to calibrate the computational modelling results over the injection and PISC phases of the project. Calibrating the computational model with pressure and temperature data from the injection zone will lead to more accurate predictions of pressure plume behavior over time. The AoR and Corrective Action Plan further discusses how the pressure and temperature data will be used to calibrate the computational modelling, and how it might be used to trigger an early reassessment of the AoR (Attachment 2: AoR and Corrective Action, 2022).

The proposed microseismic monitoring array will have a minimum of five surface stations. One

station will be located adjacent to CCS1, and four stations will be distributed around the AoR. The objective of the array will be to monitor induced seismic events within eight (8) miles of CCS1 with a magnitude of completeness ( $M_c$ ) of 1.5. The physical locations of these stations will be optimized through a design process once the data from CCS1 and OBS1 have been analyzed. The local array will be complemented with the addition of any relevant regional seismometer stations that are available through the Incorporated Research Institutions for Seismology (IRIS) to aid in positioning events from outside the AoR.

Each standalone station will likely consist of a seismometer, digitizer, solar with battery backup, and a cell modem/antenna. Triggered data will be processed to provide magnitude and location error ellipsoids on a real-time basis and results will be reviewed by a data processor and event data can be received by the project on a daily basis. Automatic notifications will be sent for events over a certain size.

The event locations will be incorporated into the static model. It is expected that some induced seismicity may occur in the Precambrian once injection commences, and the pressure plume related to the CO<sub>2</sub> injection expands. Microseismic activity will provide qualitative information on the spatial extent of pressure plume over time. Clusters of microseismic activity in the confining zone may be an indication of containment loss that would be cause for further investigation.

## 9 References

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**ATTACHMENT 8: INJECTION WELL PLUGGING PLAN  
40 CFR 146.92(b)**

**HOOSIER #1 PROJECT**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
Cardinal Ethanol

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CO<sub>2</sub> Injection Well Location for Cardinal CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

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## **List of Acronyms**

BOP	Blow Out Preventer
CO <sub>2</sub>	Carbon Dioxide
CBL	Cement Bond Log
CCS1	Proposed Injection Well
ft	feet
LD	Lay Down
MIT	Mechanical Integrity Test
ND	Nipple Down
NU	Nipple Up
OPC	One Carbon Partnership, LP
P&A	Plugging and Abandonment
PNL	Pulsed Neutron Log
POOH	Pull out of hole
PU	Pick Up
QASP	Quality Assurance and Surveillance Plan
RAT	Radioactive Tracer Log
RIH	Run in Hole
RU	Rig Up
TD	Total Depth

One Carbon Partnership, LP (OCP) will conduct injection well plugging and abandonment (P&A) according to the procedures below at a time during the project following the cessation of injection that is deemed appropriate.

## **1 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure**

Prior to any plugging operations, bottomhole pressure data from the bottomhole gauges set in the Proposed Injection Well (CCS1) will be reviewed. This data will be used to determine an appropriate kill fluid weight.

## **2 Planned External Mechanical Integrity Test(s)**

OCP will conduct at least one of the tests listed in Table 1 to verify external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

Following the operations to kill the well, testing of the external mechanical integrity will be performed. This testing will include one or more of the following:

- Temperature Log,
- Radioactive Tracer (RAT) Log,
- Cement Bong Log (CBL),
- Pulsed Neutron Log (PNL).

Prior to any field mobilization or operations, proper notification will be given to the agency. Within this notification, the specific logs and/or tests to be run to determine external mechanical integrity will be provided. The list above is an example of logs that would likely be run to confirm external mechanical integrity and should not be considered to be a comprehensive or final list for this project.

Note the following:

- i. Example procedures for the logging techniques provided above can be found in the Pre-Operational Testing Program or the Testing and Monitoring Plan sections of this application (Attachment 5: Pre-Op Testing Program, 2022) and (Attachment 7: Testing And Monitoring, 2022).
- ii. Specifications on the tools that will be used for this testing can also be found in these same sections or the Quality Assurance Surveillance Plan (QASP) section of this application.
- iii. Criteria for acceptable logging results can be found in the Testing and Monitoring Plan as well as the QASP section of the permit application.

**Table 1. Potential MITs for CCS1.**

<b>Test Description</b>	<b>Location</b>
Temperature Log	Along wellbore via wireline well log
RAT Log	Along wellbore via wireline well log
CBL	Wireline well log
PNL	Along wellbore via wireline well log

### **3 Information on Plugs**

OCP will use the materials and methods noted in Table 2 to plug the injection well. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the carbon dioxide (CO<sub>2</sub>) stream (Attachment 4: Well Construction, 2022). The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

The general plugging methodology is as follows:

- Approximately 500 foot plugs to be used throughout the well,
- CO<sub>2</sub>-resistant cement to be used from Total Depth (TD) to approximately 500 feet (ft) above the Eau Claire Formation,
- Class A cement to be used 500 ft above the Eau Claire Formation to surface.

**Table 2. Plugging details for CCS1.**

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of boring in which plug will be placed (in.)	6.276	6.276	6.276	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	3,600	3,100	2,600	2,100	1,600	1,100	600
Sacks of cement to be used (each plug)	101	100	100	90	90	90	110
Slurry volume to be pumped (ft <sup>3</sup> , bbl)	109.4 19.5	107.4 19.1	107.4 19.1	107.4 19.1	107.4 19.1	107.4 19.1	128.9 23.0
Slurry weight (lb/gal)	16.0	16.0	16.0	15.5	15.5	15.5	15.5
Calculated top of plug (ft)	3,100	2,600	2,100	1,600	1,100	600	0
Bottom of plug (ft)	3,609	3,100	2,600	2,100	1,600	1,100	600
Type of cement or other material	EverCRETE*			Class A			
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balance			Balance			

\*EverCRETE CO<sub>2</sub> resistant cement (or an equivalent)  
Mark of Schlumberger

## 4 Narrative Description of Plugging Procedures

### 4.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), OCP will notify the regulatory agency at least 60 days before plugging the well and provide updated CCS1, if applicable.

### 4.2 Plugging Procedures

In compliance with 40 CFR 146.92, the following will be done:

1. The regulatory agency will be notified at least 60 days before any field activity begins with an updated plugging plan.
2. Move in the workover rig and rig up (RU) on CCS 1.
3. CO<sub>2</sub> pipelines will be marked and noted with the rig supervisor and facility manager.
4. Hold safety meeting with all available rig crew, contractors and facility personnel.
5. Based on the calculated kill fluid weight needed from the bottom hole pressure survey, kill the well.
  - a. It is anticipated that approximately 9.5 pounds per gallon will be appropriate. This weight is subject to change based on the result of the bottomhole pressure survey. It is noted that regardless of the results of the pressure survey, 9.5 pounds per gallon will be the minimum fluid weight.
6. Ensure that rig pump or other suitable pump is rigged up to the well. Pressure test all lines to minimum 2,500 psi. Perform annulus pressure test.

7. Fill tubing and cased hole volume with kill brine. Monitor tubing pressure to ensure the well is dead.
8. Once the casing and tubing are dead, nipple down (ND) the well head.
9. Nipple up (NU) and test blow out preventers (BOPs).
10. Latch onto and remove tubing hanger from wellhead.
11. Lay down (LD) tubing hanger.
12. Latch onto injection string.
13. Unlatch from packer
  - a. Note that, at this time, the well is likely to u-tube. Ensure rig pump is connected to the top side, close the BOPs, and slowly circulate out the annulus fluid while maintaining a full column of fluid (as feasible).
14. Pull out of hole (POOH) with tubing and LD same.
  - a. Fill hole as necessary.
15. Pick up (PU) work string with packer pulling tool and run in hole (RIH).
16. Latch onto Packer and remove same.
17. POOH with work string and packer. LD same.
18. RIH with open end work string.
19. Tag bottom. Note tag depth
20. Pump plug #1.
  - a. Pump 20 ft off bottom.
  - b. Target height of plug should be 500 ft. Plug volume should be as detailed in Table 2.
  - c. Slowly pull out of hole is necessary while pumping plug.
21. Target top of hole should be approximately 3,100 ft. Trip work string out to approximately 3,000 ft. Wait at 3,000 ft for approximately two hours.
  - a. Wait time is dependent on hardening time for cement.
  - b. Wet samples of cement should be taken.
22. RIH and tag top of cement. Note top of cement. Ensure cement top has not moved.
23. Repeat steps 20 through 22 plugs 2 and 3.
  - a. Note that cement used in plugs one through three will be CO<sub>2</sub> resistant.
  - b. Target top of plug three to be 2,100 ft. This depth is approximately 500 ft above the top of the Eau Claire Formation.
24. Flush wellbore with brine.
25. RIH with work string and tag top of cement. Note top of cement.
26. Pump plug # 4.
  - a. 20 ft off bottom.
  - b. Target height of plugs should be 500 ft. Plug volume should be as detailed in Table 2. Plug to be pumped as balance plug.
  - c. Slowly pull out of hole as necessary while pumping plug.
27. Trip out work string to 100 ft above projected top with cement. Wait two hours.
  - a. Wait time is dependent on hardening time for cement.
  - b. Wet samples of cement should be taken.
28. RIH and tag top with cement. Note top of cement
29. Pump remaining 500-foot plugs by repeating steps 34 through 36.
30. Ensure cement is to surface. Fill from surface if necessary.
31. ND BOPs

32. Rig down rig. All casing should be cut to minimum three ft below ground level and have plate with well information welded on top.
33. Fill and level ground as necessary.

Note that the procedure presented above assumes that no contingencies are necessary. Cement volumes, pumping pressures and weights are subject to change based on geologic and field conditions. This plan will be updated following the drilling and completion of CCS1.

All materials and equipment to be used in this procedure are to be cement resistant to 500 ft above the Eau Claire Formation.

Any contingency plans that are necessary will be provided for as part of the formal procedure submitted 60 days before any field activities.

Following the completion of field activities, a report detailing the procedures and process followed to plug this well will be submitted to the agency. This report will be submitted within 60 days of the completion of plugging.

Figure 1 displays the theoretical plugging schematic for CCS1.

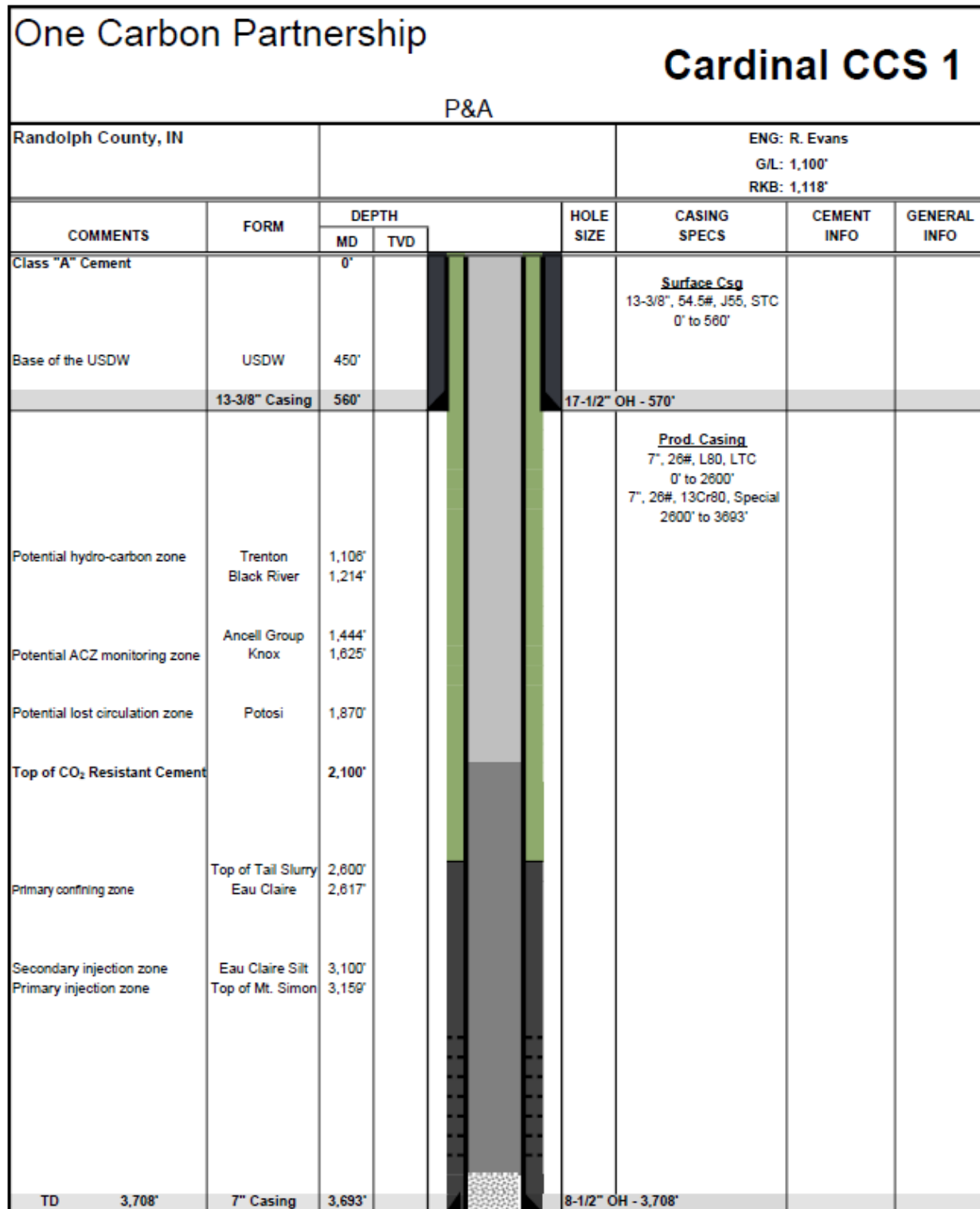


Figure 1. Injection Well Plugging Schematic

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Plan revision number: N/A

Plan revision date: N/A

**ATTACHMENT 9: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN  
40 CFR 146.93(a)**

**HOOSIER #1 PROJECT**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
Cardinal Ethanol

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CO<sub>2</sub> Injection Well Location for CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator Name: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

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## **List of Acronyms**

2D	Two-Dimensional
3D	Three-Dimensional
ACZ	Above Confining Zone
ACZ1	Proposed Above Confining Zone Well
AoR	Area of Review
BHFP	Bottomhole Flowing Pressure
BHP	Bottomhole Pressure
CCS1	Proposed Injection Well
CO <sub>2</sub>	Carbon Dioxide
DIC	Dissolved Inorganic Carbon
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response Plan
FOT	Fall-off Test
ICP	Inductivity Coupled Plasma
IDNR	Indiana Department of Natural Resources
kT/Y	kiloton per year
kv/kh	vertical/horizontal permeability
Mc	Magnitude of Completeness
MD	Measured Depth
MIT	Mechanical Integrity Test
MS	Mass Spectrometry
NRMS	Normalized Root Mean Square
OBS1	Deep Observation Well
OC	One Carbon Partnership, LP
OES	Optical Emission Spectrometry
PISC	Post Injection Site Care and Site Closure
PNL	Pulsed Neutron Logging
QASP	Quality Assurance and Surveillance Plan
TBD	To Be Determined
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USDW1	Proposed Lowermost USDW Monitor Well

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that the Hoosier#1 Project will perform to meet the requirements of 40 CFR 146.93. The project is proposing an alternative timeframe of ten years. The position of the carbon dioxide (CO<sub>2</sub>) plume, pressure front, and shallow ground water quality will be monitored for the 10-year PISC period over which CO<sub>2</sub> plume and pressure front are expected to stabilize based on current computational modeling (Section 4.0).

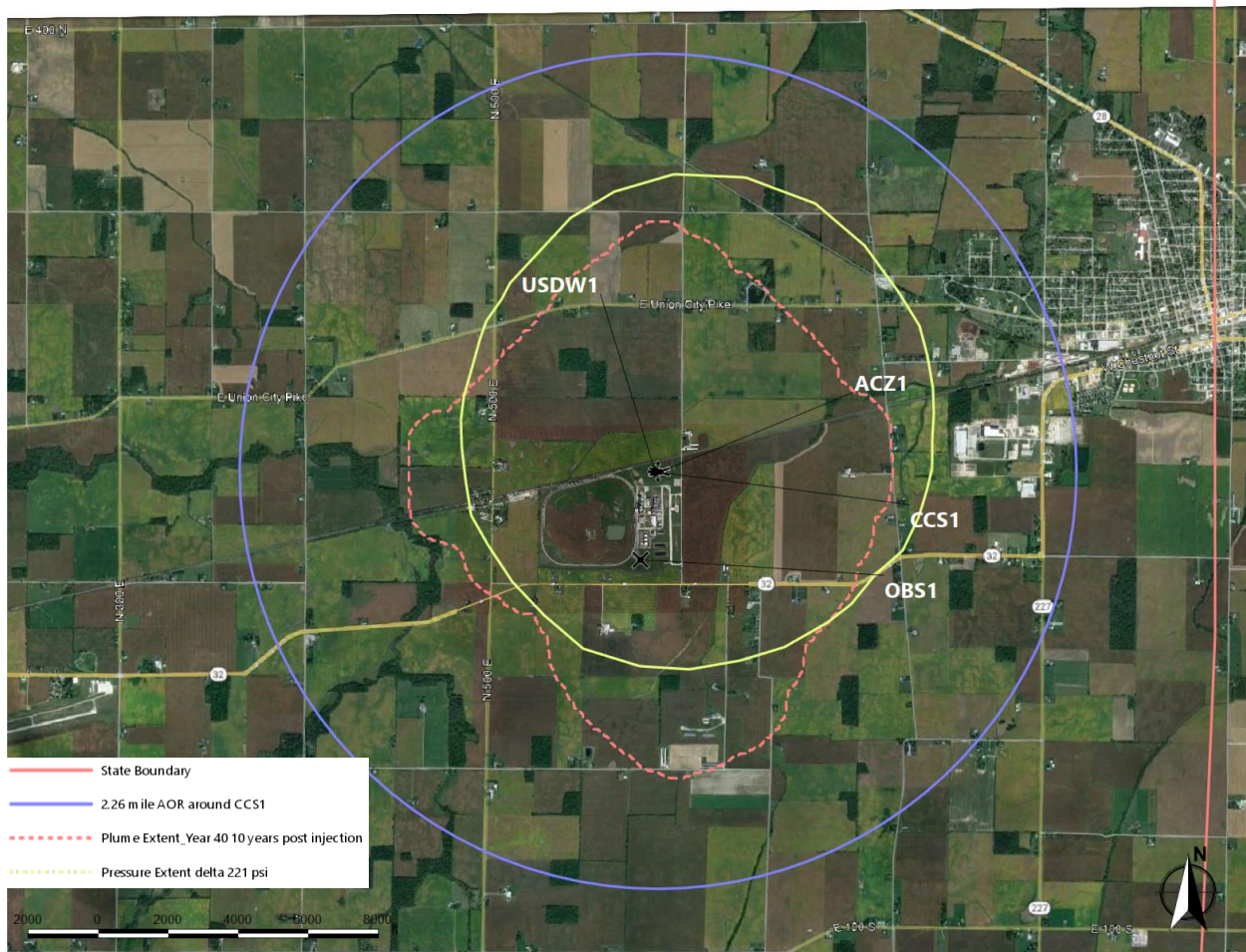
### **1.0 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]**

Based on the computational modeling performed as part of the Area of Review (AoR) delineation (Section 4.2), the injection zone pressure is expected to decrease to pre-injection levels after approximately two years. Additional information on the projected post-injection pressure declines and differentials is presented in the AoR and Corrective Action Plan (Attachment 2: AoR and Corrective Action, 2022).

The pressure plume is defined as the area where the delta pressure is greater than the critical pressure. The critical pressure is the increase in pressure necessary to allow fluids to migrate up an open conduit to the lowermost Underground Source of Drinking Water (USDW). Critical pressure, in this case, is 227 psi. The computational modeling demonstrates that the pressure will rapidly decline in the two years following the cessation of injection and that the pressure plume will decrease in size until pressures decrease below the critical pressure after approximately two years. Within 250 feet of the injection well, the maximum pressure rise is estimated to be 378 psi at the end of the injection period.

### **2.0 Predicted Position of the CO<sub>2</sub> Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]**

Figure 1 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe that represents the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84. A list of water wells located within the AoR are provided in the AoR and Corrective Action Plan (Attachment 2: AoR and Corrective Action, 2022).



**Figure 1. Map of the predicted extent of the CO<sub>2</sub> plume and pressure front at site closure.**

### 3.0 Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

The PISC monitoring, which includes shallow groundwater, above confining zone (ACZ), injection zone pressures, and geophysical monitoring (as described in the following sections), will meet the post injection monitoring requirements of 40 CFR 146.93(b)(1). The results of all the post-injection monitoring will be submitted annually, within thirty days of the conclusion of the activities or receipt of processed data, whichever is later, as described under “Schedule for Submitting Post-Injection Monitoring Results,” following.

A Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided (Attachment 11: QASP, 2022).

Table 1 summarizes the monitoring activities that will take place during the PISC phase of the project. The project will continue to monitor pressures within the Mt. Simon Sandstone in the Proposed Injection Well (CCS1) and Deep Observation Well (OBS1) until the pressures drop to below the critical pressure rise of 227 psi. The pressure within the Mt. Simon Sandstone is expected to begin to dissipate once CO<sub>2</sub> injection ceases based on the computation modelling (Section 4.0). The injection zone pressure measurements are expected to verify the modeling

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results. This pressure data will be used to further calibrate the computational modelling in the PISC phase.

Downhole pressure is to be monitored continuously in both wells for two years or until the bottomhole pressure (BHP) change in CCS1 is below the critical pressure (227 psi), whichever occurs later. At this point, annual static gradient surveys will be collected from CCS1, and pressure monitoring will cease in OBS1.

The ACZ monitoring zone pressures will also continue to be monitored to confirm the containment of CO<sub>2</sub> within the injection zone. Fluid samples will be taken from the ACZ monitoring zone once per year for geochemical and isotopic analysis to further verify CO<sub>2</sub> containment. Shallow groundwater fluid samples will also be obtained each year for geochemical and isotopic analysis.

Any potential microseismic activity will likely fall-off once the injection phase of the project is complete and the associated pressure plume begins to dissipate. The microseismic monitoring will likely be phased out as activity decreases. This will be evaluated in the first months of the project's PISC phase. The Underground Injection Control (UIC) Program Director will be consulted prior to ceasing any monitoring activities during the PISC phase of the project.

The project proposes to acquire two time-lapse three-dimensional (3D) surface seismic surveys in the PISC phase of the project. One will be acquired the year either at the end of the injection phase or at the start of the PISC phase of the project. The last survey will be acquired in the eighth (8<sup>th</sup>) year of the PISC phase of the project. The objectives of these two surveys include:

- Verification of continued CO<sub>2</sub> containment in the injection zone,
- Demonstration of the stability of the CO<sub>2</sub> plume after the injection phase of the project,
- To provide data for the calibration and verification of the computational modelling.

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**Table 1: Summary of proposed testing and monitoring activities to take place during the PISC phase of the project.**

Monitoring Activity	PISC Frequency*	Location	Depth Range (MD ft)**
<b>Groundwater Monitoring</b>			
Groundwater Sampling	Annual (Q2 of each year)	USDW1 ACZ1 12 stations TBD	Varying
Isotope Analysis	Annual (Q2 of each year)	USDW1 ACZ1 12 stations TBD	Varying
<b>Pressure Monitoring</b>			
Downhole Pressure	Continuous*	CCS1 OBS1	Above Packer (TBD) Mt. Simon Sandstone (TBD)
Wellhead Pressure	Continuous	ACZ1	Knox Formation (TBD)
<b>Mechanical Integrity Tests</b>			
Mechanical Integrity Test (MIT) Part I: Annulus Pressure Test	Year 5 Year 10	CCS1 OBS1	Surface Surface
MIT Part II: Temperature Logging	Year 5 Year 10	CCS1 OBS1 ACZ1	TBD
<b>Plume Verification Monitoring</b>			
Pulsed Neutron Logging (PNL)	Year 1, Year 3, Year 5, Year 7, Year 9	CCS1 OBS1	To the Packer TBD
Microseismic Monitoring	Continuous	Minimum 5 Surface Stations	Injection Zone Confining Zone
Time-lapse 3D Surface Seismic Data	Q2 Year 0 Q2 Year 8	Area sufficient to image an 8.97 mi <sup>2</sup> plume	Imaging of CO <sub>2</sub> plume and overburden
*Downhole pressure is to be monitored continuously in both wells for two (2) years, or until the BHP change in CCS1 is below the critical pressure (227 psi), whichever occurs later. At this point, annual static gradient surveys will be collected from CCS1, and pressure monitoring will cease in OBS1.			
** To be confirmed after well is drilled			

Cardinal Ethanol owns the land on which CCS1, OBS1, and the Proposed Above Confining Zone Well (ACZ) are located and also owns (or will have surface access rights to) the land that the shallow groundwater wells are located on. Access to the wells for testing is not anticipated to be a problem as surface access will be negotiated as part of the landowner leases for the project.

### 3.1 Monitoring Above the Confining Zone

The monitoring plan for the PISC is designed to be adaptive and respond to evolving project risks over time. At this point in the project, no phased monitoring has been planned for ACZ1 groundwater monitoring; however, this may be re-assessed as the project progresses. No changes will be made to the PISC without informing the UIC Program Director (40 CFR 146.93 (a)(3)).

Table 2 presents the proposed ACZ groundwater monitoring methods, locations, and frequencies. The ACZ monitoring zone will likely be in the Knox Formation with the exact depth to be determined through the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022). For fluid sampling, a bailer system that maintains the formation pressure of the sample, will be used to collect water samples to be analyzed for dissolved inorganic carbon, alkalinity, pH, and the isotopic analyses. Samples for all other analytes will be collected with an open-ended bailer. Prior to sample collection the well will be swabbed to remove stagnant water from the well and ensure representative water is collected from the formation. The fluid swabbed from the well will be monitored for field parameters, such as pH, specific conductance, and temperature, using a calibrated water quality meter. Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Further detail on specifications, sample collection methods, analytical techniques, detection limits, and means of storing and transporting fluid samples is provided in the QASP (Attachment 11: QASP, 2022).

**Table 2. ACZ1 Monitoring of ground water quality and geochemical changes above the confining zone.**

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Shallow Groundwater	Aqueous geochemistry and stable isotopes	USDW1 12 groundwater wells TBD	Lowermost USDW Distributed throughout AoR	Annual (Q2/yr)
Knox Formation	Aqueous geochemistry and stable isotopes	ACZ1	Adjacent to CCS1	Annual (Q2/yr)

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Table 3 identifies the initial groundwater parameters to be monitored and the analytical methods that will be used for the samples in the baseline analysis of the data.

**Table 3. Summary of analytical and field parameters for ground water samples.**

<b>Parameters</b>	<b>Analytical Methods<sup>(1)</sup></b>
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Ti, Ca, Fe, K, Mg, Na, and Si	ICP <sup>(2)</sup> -MS <sup>(3)</sup> , EPA Method 6020 ICP-OES <sup>(4)</sup> , EPA Method 6010B
Anions: Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0
Dissolved CO <sub>2</sub>	Coulometric Titration ASTM D513-11
Isotopes: $\delta^{13}\text{C}$ Dissolved Inorganic Carbon (DIC)	Isotope ratio mass spectrometry <sup>(5)</sup>
Total Dissolved Solids	Gravimetry APHA 2540C
Water Density (field)	Oscillating body method
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Conductivity/Resistivity (field)	APHA 2510
Temperature (field)	Thermocouple
Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director. Note 2: Inductivity Coupled Plasma Note 3: Mass Spectrometry Note 4: Optical Emission Spectrometry Note 5: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)	

At this time, a laboratory has not been selected for the groundwater sampling and analysis. However, all sampling and analytical measurements will be performed in accordance with project quality assurance requirements. Samples will be tracked using appropriately formatted chain-of-custody forms (Attachment 11: QASP, 2022).

The results of the geochemical and isotope analysis will be delivered in the form of lab reports. If anomalous changes in the aqueous geochemistry are observed in ACZ, lowermost USDW, or shallow groundwater monitoring zones, new samples will be obtained from the affected zone to verify the changes. The frequency with which fluid samples are obtained for analysis from that zone will also be increased.

As a precautionary measure, the fluid sampling frequency for the shallow groundwater monitoring wells will also be increased. If the injected CO<sub>2</sub> has a unique isotopic signature from the existing isotopes in the overlying formation, a new round of samples will be collected for isotopic analysis from the affected formation. Anomalous changes may also trigger the need for additional well integrity testing in both the CCS1 and OBS1 to ensure that no well integrity

issues have developed since the last set of external mechanical integrity tests. A combination of anomalous pressure, geochemical, and well integrity testing results may result in the decision to acquire a time-lapse 3D surface seismic survey before the survey scheduled in year eight of the PISC to determine the size of the leakage accumulation (Table 1).

Table 4 presents information about the wellhead pressure monitoring to be used in the ACZ1 well. Further detail and specifications on the equipment to be used in the ACZ1 well is provided in the QASP. The pressure data will be stored as time stamped data. Migration of injection zone fluids into the deep ACZ zone will likely first be identified through pressure changes in the formation. An increasing pressure trend in the ACZ zone would suggest that migration of injection zone fluids beyond the confining zone has occurred. While any increasing trend in pressure will be evaluated, an increase in pressure greater than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid migration out of the injection zone. Such an increase in pressure would initiate more frequent fluid sampling and analysis for geochemical parameters from the formation and require additional external well integrity investigations for CCS1 or OBS1.

**Table 4. Sampling and recording frequencies for continuous monitoring in ACZ1**

Parameter	Device(s)	Location	Minimum Sampling Frequency	Minimum Recording Frequency
Pressure	Wellhead Pressure Gauge	ACZ1	Continuous (every hour)	Continuous (every hour)
Notes: <ul style="list-style-type: none"> <li>• Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.</li> <li>• Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.</li> </ul>				

### 3.2 CO<sub>2</sub> Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

The project will employ direct and indirect methods to track the extent of the CO<sub>2</sub> plume and the presence or absence of elevated pressure throughout the PISC phase.

Table 5 presents the direct and indirect methods that will be used to monitor the CO<sub>2</sub> plume including the activities, locations, and frequency of sampling.

The quality assurance procedures for seismic monitoring methods will be performed as described in (Attachment 11: QASP, 2022).

**Table 5. Post-injection phase CO<sub>2</sub> plume monitoring**

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
<b>Direct Plume Monitoring</b>				
Knox, Eau Claire, and Mt. Simon Formations	Pulsed Neutron Logging	CCS1 OBS1	TBD	Year 1, Year 3, Year 5, Year 7, Year 10
<b>Indirect Plume Monitoring</b>				
Overburden, Eau Claire, and Mt. Simon Formations	Time-lapse 3D Surface Seismic Data	Over project AoR	Area sufficient to image an 8.97 mi <sup>2</sup> plume	Q2, Year 0 Q2, Year 8

The Pulsed Neutron Logging (PNL) will be received as LAS files and interpreted products that can be imported into the static model. PNL will be used to monitor the distribution and saturation of CO<sub>2</sub> adjacent to the wellbore in OBS1. In CCS1, it is expected that the near wellbore zone will be saturated with CO<sub>2</sub> and the plume will take up the entire injection zone, so there will be little value in running the PNL through the injection zone. However, the PNL will be run through the ACZ monitoring zone to verify that there are no accumulations of CO<sub>2</sub> adjacent to the wellbore above the confining layer in CCS1. Technical details on PNL tools can be found in the QASP (Attachment 11: QASP, 2022).

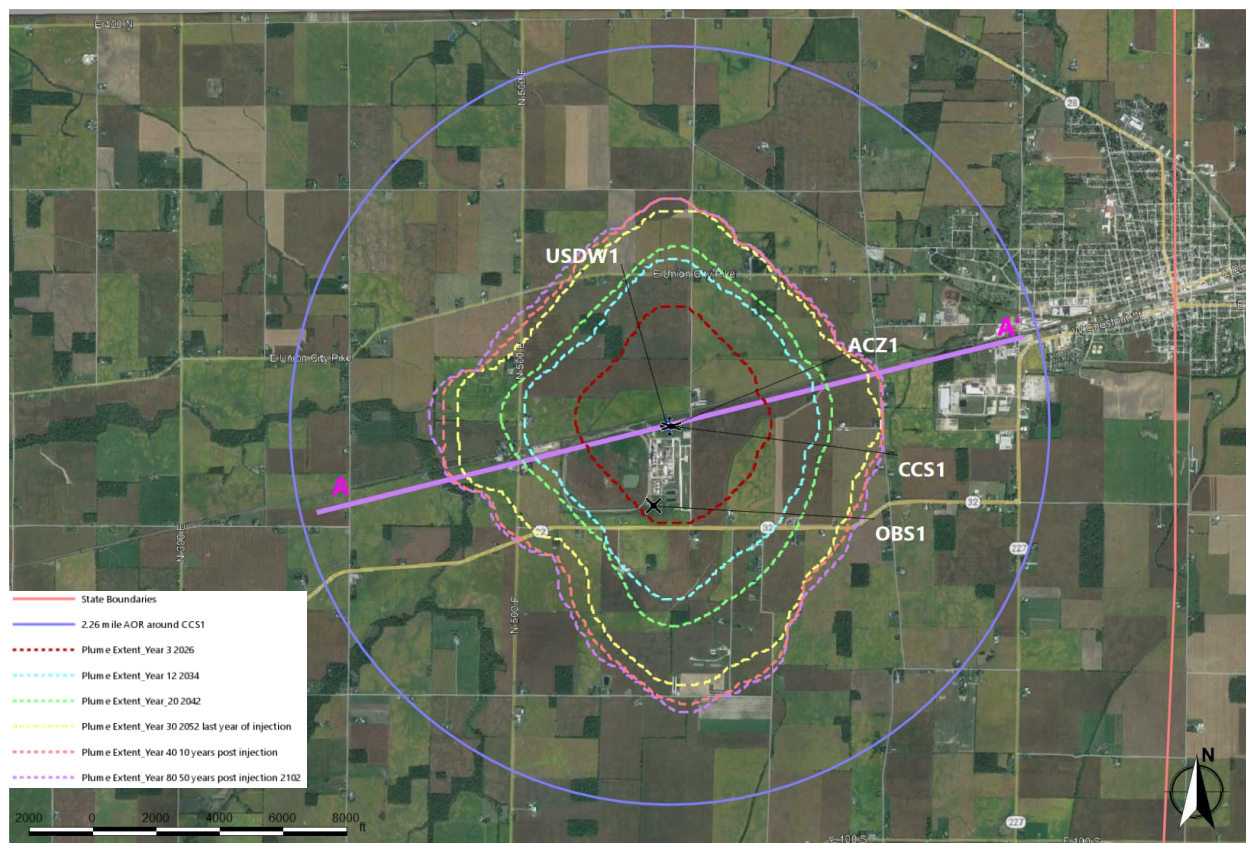
Surface seismic data is delivered in a variety of formats including acquisition and processing reports and SEG-Y data files from a variety of points in the processing flow. In the context of time-lapse analysis, an assessment will be provided on the differences between the baseline and time-lapse surveys as well as data files that can be incorporated into the static model. The injection of CO<sub>2</sub> and expansion of the plume is expected to change the acoustic impedance of intervals within the Mt Simon Sandstone and increase the time it takes seismic waves to travel through the CO<sub>2</sub> plume over time. Both the acoustic impedance and travel time changes will be used to track CO<sub>2</sub> plume during the PISC phase of the project. In addition, time-lapse analysis metrics such as normalized root mean square (NRMS) and predictability can be used to track the plume. The time-lapse surface seismic data will also be monitored for changes that may suggest that CO<sub>2</sub> has migrated past the confining layer and into the ACZ monitoring zone.

At this time, no direct fluid sampling is planned for the injection zone for the PISC phase of the project. The CO<sub>2</sub> plume is expected to intersect OBS1 within three years of the start of injection operations (Figure 2). Once free phase CO<sub>2</sub> breaks through at OBS1, the project will stop taking fluid samples and analyzing for isotopes from the Mt Simon Sandstone.

Table 6 presents the direct and indirect methods that will be used to monitor the pressure front.

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**Figure 2: Time-lapse CO<sub>2</sub> plume development map over 3, 12, 20, and 30 years of injection as well as 10- and 50-years post injection. Note the relative stability of the CO<sub>2</sub> plume radius after injection operations cease.**

**Table 6. Post-injection phase pressure-front monitoring**

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
<b>Direct Pressure-Front Monitoring</b>				
Mt Simon Sandstone	Pressure Monitoring	CCS1 OBS1	Exact depth TBD	Continuous (Minimum every one (1) minute)*
<b>Indirect Pressure-Front Monitoring</b>				
Eau Claire Formation Mt. Simon Sandstone	Microseismic Monitoring	Minimum 5 Surface Stations	Events within an 8 mi radius of CCS1	Continuous (Minimum every 10 seconds)
*Downhole pressure is to be monitored continuously in both wells for two years, or until the BHP change in CCS1 is below the critical pressure (227 psi), whichever occurs later. At this point, annual static gradient surveys will be collected from CCS1, and pressure monitoring will cease in OBS1.				

The downhole pressure sensors will be programmed to measure and record pressure and temperature data in one-minute intervals. The downhole pressure will be monitored in both wells for two years, or until the bottom hole pressure change in CCS1 is below the critical pressure (227 psi), whichever occurs later. After this time, annual static gradient surveys will be collected from CCS1 via wireline, and pressure monitoring will cease in OBS1.

Should either of the well's BHP gauge fail during the first two-year period, positive pressure readings at the wellhead will be used to verify continued pressure fall-off until the gauge can be replaced. Should positive pressure at the wellhead no longer be present, a suitable, periodic method of determining hydrostatic fluid level (i.e., shooting fluid levels or similar method) will be used to calculate the BHP until the gauge can be replaced.

The final monitoring interval in both wells will be determined after CCS1 has been drilled and the well logs have been analyzed (Attachment 5: Pre-Op Testing Program, 2022).

The results of the aqueous geochemistry and isotope analysis, PNL, and time-lapse 3D surface seismic data will all be integrated to develop a comprehensive understanding of the CO<sub>2</sub> plume behavior during the PISC phase. PNL and time-lapse 3D surface seismic data can be incorporated into the static model for comparison to the computational modeling predictions at different points in time. The data can be used to constrain the computational modeling results and produce better plume predictions over the course of the project.

The PNL data will be used to calibrate the computational modeling and provide information on the vertical and horizontal plume behavior as well as supply more detailed and direct measurement of CO<sub>2</sub> saturations than indirect seismic methods. The time-lapse 3D surface seismic data will be used to update the models after the data has been analyzed. If the CO<sub>2</sub> plume monitoring data diverges significantly from the modeled plume predictions, it may result in a reassessment of the AoR as per the AoR and Corrective Action Plan (Attachment 2: AoR and Corrective Action, 2022).

Based on the current computational modeling results, the CO<sub>2</sub> plume is expected to stabilize quickly during the PISC phase of the project (Figure 2). Time-lapse 3D surface seismic surveys acquired during Q2 in Year 0 and Year 8 of the PISC phase of the project will demonstrate the stabilization of the CO<sub>2</sub> plume and be used to verify the computational modelling results.

### **3.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]**

All PISC monitoring data and results obtained using the methods described above will be submitted to EPA in annual reports. These reports will contain information and data generated during the reporting period (i.e., well-based monitoring data, sample analysis, and results from updated site models).

### **4.0 Alternative PISC Timeframe [40 CFR 146.93(c)]**

The project will conduct post-injection monitoring for a ten-year period following the cessation of injection operations. A justification for this alternative PISC timeframe is provided following.

#### **4.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i)**

The CO<sub>2</sub> plume is expected to expand to 1.646 miles after 30 years of injection (Figure 2). It will continue to expand to 1.690 miles after 50 years post injection due to the buoyancy of the CO<sub>2</sub>. Gas trapping and CO<sub>2</sub> dissolution in water will continue to increase over time and will mitigate the buoyancy effect to some extent. Expansion after 50-years post injection is negligible. Additional figures and cross sections on the CO<sub>2</sub> plume development can be found in (Attachment 2: AoR and Corrective Action, 2022).

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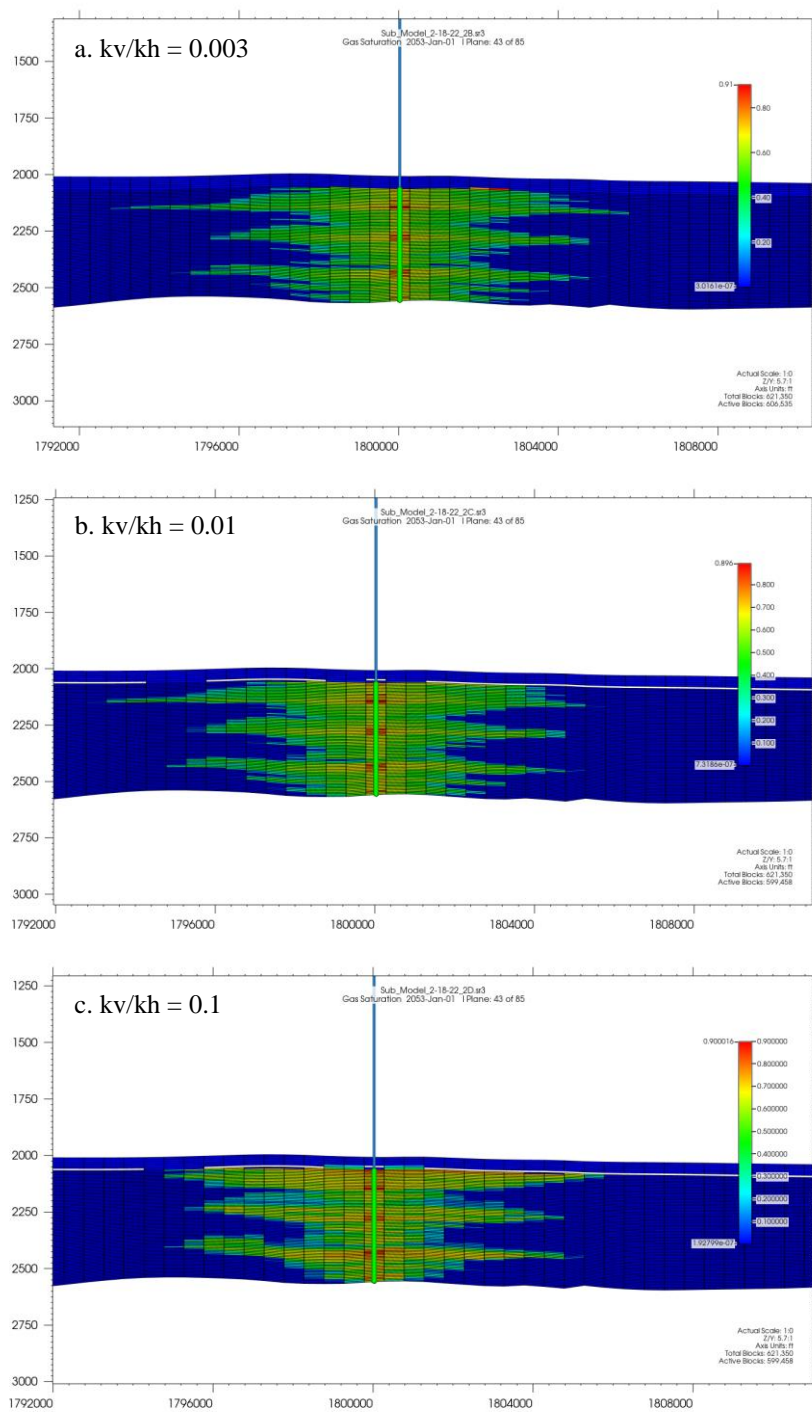
The kv/kh (vertical/horizontal permeability) ratio is a key uncertainty given the lack of deep well data in the region. From pressure transient analysis of well test data from the INEOS (BP Lima) UIC Project, it was estimated that kv/kh is approximately 0.003. Sensitivity cases were run with kv/kh values equal to 0.01 and 0.1 (Figure 3). The individual simulations indicated that the CO<sub>2</sub> plume would be smaller with increasing values of kv/kh (Table 7). As kv/kh values increase the rate of vertical migration of the CO<sub>2</sub> is higher resulting in more residual gas trapping. A very low kv/kh would be representative of a higher number of baffles in the formation that would prevent upward migration of the CO<sub>2</sub> and encourage horizontal migration. Currently, it is believed that the value 0.003 is a realistic but conservative estimate given the results from the INEOS (BP Lima) UIC Project. These results will be re-assessed once as site specific data is collected over the pre-operational and operational phases of the project.

**Table 7: Impact of varying kv/kh values on the CO<sub>2</sub> plume radius**

<b>Kv/kh</b>	<b>CO<sub>2</sub> Plume Radius (mi)</b>
0.003	1.32
0.01	1.23
0.1	1.02

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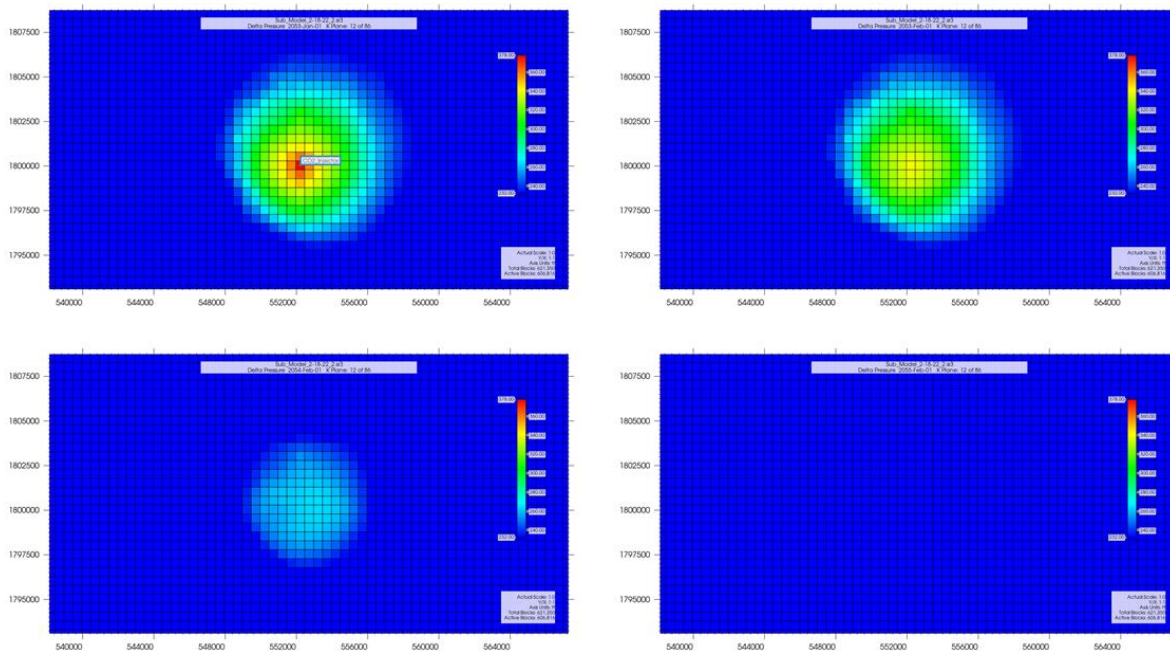


**Figure 3: Effect of  $k_v/k_h$  ratio on CO<sub>2</sub> plume size. Increasing  $k_v/k_h$  results in smaller CO<sub>2</sub> plume size as a result of higher rates of residual gas trapping. a.  $k_v/k_h = 0.003$ , b.  $k_v/k_h = 0.01$ , c.  $k_v/k_h = 0.1$**

#### 4.2 Predicted Timeframe for Pressure Decline – 40 CFR 146.93(c)(1)(ii)

The pressure plume is irregular in shape due to the heterogeneity and dip of the injection zone. The maximum radius of the pressure plume is calculated to be 1.69 miles after 30 years of injection based on a delta pressure of 227 psi (Attachment 2: AoR and Corrective Action, 2022). The computational modeling results show a rapid decline in the size of the pressure plume once injection operations cease (Figure 4 and Figure 5). Figure 4 demonstrates that there are no grid blocks with delta pressure equal to or greater than the minimum delta pressure of 227 psi after a period of two years. Figure 5 shows the margin between the sustained and maximum bottomhole flowing pressure (BHFP) to be about 600 psi, and the BHFP declines rapidly post injection.

The pressure plume decline is sensitive to the average flow capacity (kh) of the injection site. A higher kh would result in a more rapid decline, while a lower kh would result in a slower decline. In any event, the decline period is expected to be short based on the current computational modeling.



**Figure 4: Delta pressure at time = 0-, 30-, 365-, and 730-days post injection. The pressure plume, which is defined by a delta p of 227 psi, is undetectable at 730-days post injection.**

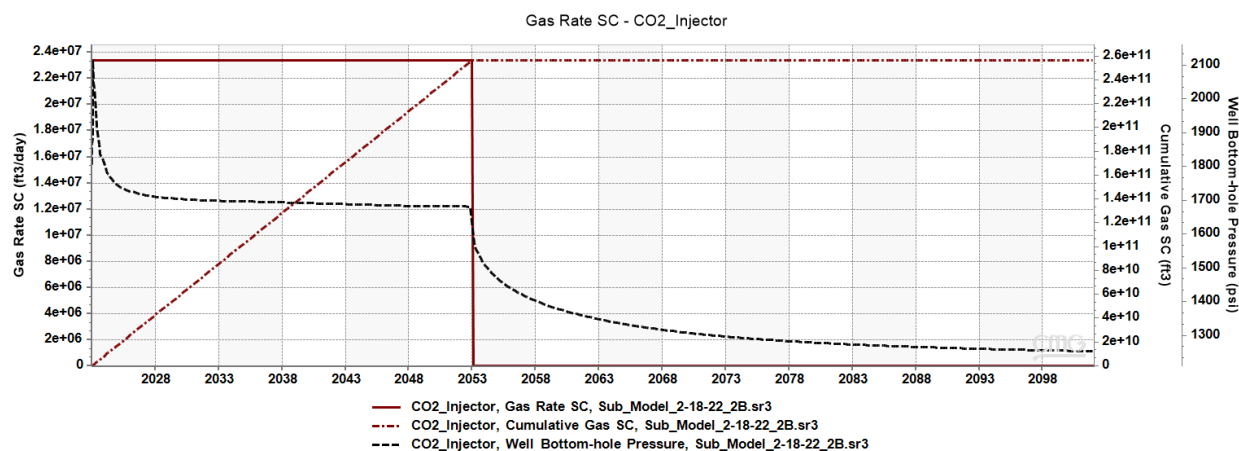


Figure 5: CO<sub>2</sub> injection rate, cumulative production, and BHFP for injection well during injection period and 50 years post injection.

#### 4.3 Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii)

The maximum spatial extent of the CO<sub>2</sub> plume occurs 50 years post injection with a radius of 1.690 miles. The CO<sub>2</sub> plume migration rate varies with time; however, on average, the plume migration rate during the injection period is 0.044 miles/year or 232 ft/yr. The average post injection plume migration rate is 0.002 miles/yr or 10.6 ft/yr. After 50 years post injection, the CO<sub>2</sub> plume migration rate is effectively zero. The primary factors affecting CO<sub>2</sub> plume migration are the storativity (porosity-height), flow capacity (permeability-height, kh), and the kv/kh ratio of the formation at the injection well site.

Sensitivities to kv/kh were discussed in Section 4.2. A small decrease in flow capacity is not expected to have an impact on the required rate of 450 kilotons per year (kT/Y) because the difference between the estimated and maximum BHFP in the base case is considerable (~600 psi). If the storativity is smaller, then a slightly larger CO<sub>2</sub> plume would result, as the increase in plume radius is approximately equal to the square root of the reciprocal of the storativity. For example, if the storativity is reduced by 25%, the CO<sub>2</sub> plume radius would be 15% larger. A CO<sub>2</sub> plume with a 1.94 mile radius would still fall well within the current AoR radius of 2.26 miles.

#### 4.4 Site-Specific Trapping Processes – 40 CFR 146.93(c)(1)(iv)-(vi)

The primary trapping mechanisms considered for this project are structural, residual gas, CO<sub>2</sub> dissolution in water, and mineral dissolution and precipitation. Figure 6 illustrates how the impact of each trapping mechanism changes with time according to the results of the computational modeling.

Initially, a large percentage, 61%, of the supercritical CO<sub>2</sub> injected will be trapped in the injection zone by the confining layer. Gas in hydrocarbon reservoirs has been known to have been trapped for millions of years providing confidence that long-term storage is possible in formations with a competent seal. Confining layer integrity and containment is a critical component of a CO<sub>2</sub> storage project. The computational modeling incorporated geomechanical information from INEOS (BP Lima) UIC Project to predict the increase in pressure on the confining zone within the pressure plume to assess the suitability of the confining zone (Attachment 1: Narrative, 2022). The estimated effective stress for the top of the injection zone/

base of the confining zone is 966 psi while the increase in pressure associated with 30 years of CO<sub>2</sub> injection is approximately 378 psi. This indicates that the confining zone is a suitable barrier to fluid migration out of the injection zone over a 30-year period.

Residual gas trapping occurs when the CO<sub>2</sub> is carried by convection currents away from the wellbore and begins to rise due to gravity segregation between the CO<sub>2</sub> and water. The CO<sub>2</sub> can become discontinuous in small pore spaces and residual amounts are trapped. The computational modeling estimated that 17% of the CO<sub>2</sub> injected would be trapped through residual gas trapping by the end of the injection period; however, over time a significant percentage of the total injected CO<sub>2</sub> is trapped through this mechanism (Figure 6). Initially, the water saturation in the pore space decreases as CO<sub>2</sub> is injected (drainage) but increases as CO<sub>2</sub> migrates upwards (imbibition). The imbibition relative permeability curve is different from the drainage relative permeability curve; this difference is known as relative permeability hysteresis. Hysteresis modeling data for a two-phase system involves a bounding drainage curve, K<sub>rg</sub>, and a trapping mechanism function with associated parameters. The trapping function determines the bounding/scanning imbibition curves. The computational modeling used the Carlson and Land model for the residual gas trapping calculations.

Gas solubility trapping is a slower process than residual gas trapping but is also an important mechanism in long-term storage. The computational modeling estimated that 22% of the CO<sub>2</sub> injected would be trapped by this mechanism by the end of the injection period (Figure 6). Solubility trapping is dependent on pressure, temperature, salinity, and surface area contact with the water. The percentage of gas trapped by dissolution increases significantly over time. The solubility correlations are based on Henry's Law, and various models are available in the modeling software including Li-Nghiem and Harvey. The effect of salinity can be modeled by either the Cramer or Bakker correlations.

Mineral dissolution and precipitation reactions are very slow, and it is estimated that significant amounts of trapping will occur only after hundreds or thousands of years post injection. In this study, anorthite, calcite, and kaolinite were considered as precipitates. After 100-years post injection, the mineralization of CO<sub>2</sub> accounted for only 0.4% of the total gas trapped. Figure 7 shows the mole change of each mineral over time.

It has been speculated, and generally accepted by the CCS community, that over a period of 10,000 years 90% of the injected CO<sub>2</sub> will be immobilized in the injection zone because of the mechanisms described above. The remaining 10% will continue to be trapped by the confining layer until eventually all the CO<sub>2</sub> becomes immobile.

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Plan revision date: N/A

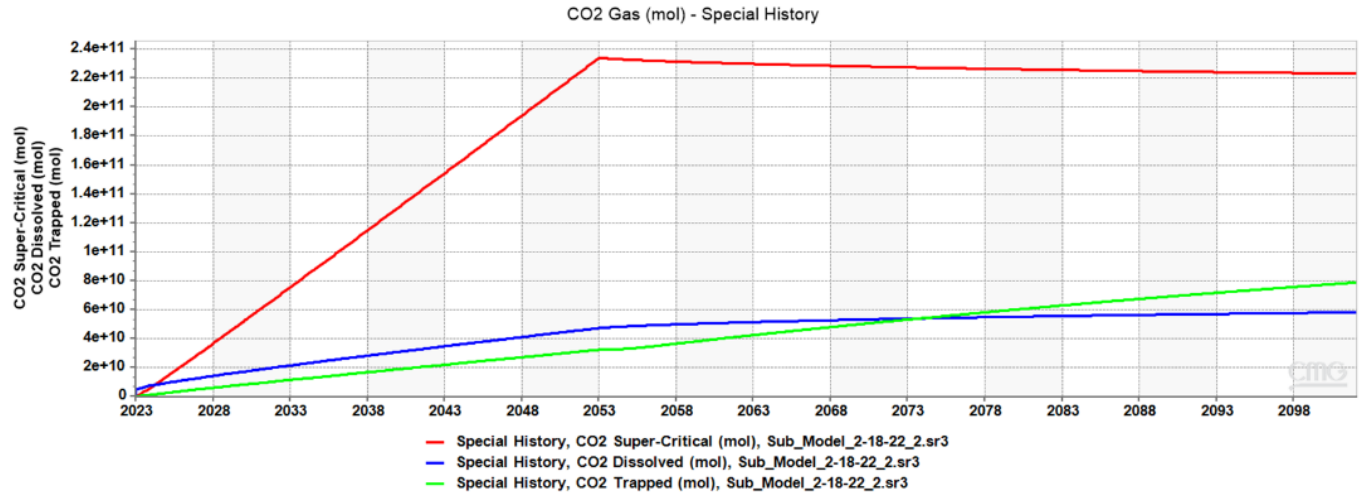


Figure 6: Breakdown of CO<sub>2</sub> mols for free phase supercritical, dissolved, and trapped phases during the injection period and 100 years post injection. Mineralization is negligible during this period.

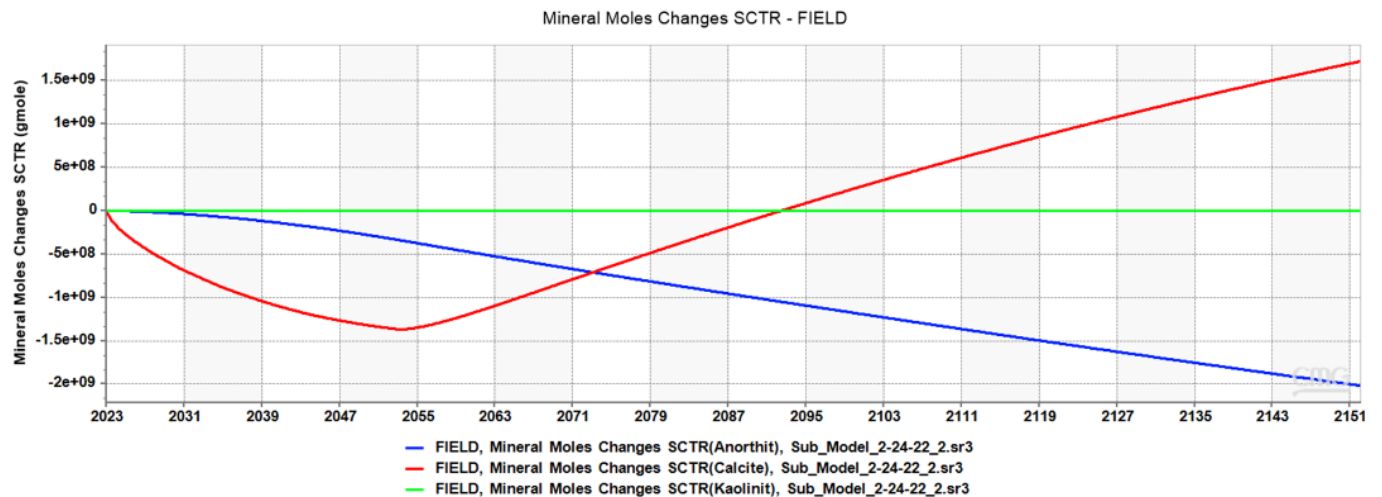


Figure 7: Mineral mole change over time for anorthite, calcite, and kaolinite. Initially, calcite is dissolved, but then starts to precipitate again and becomes the primary mineral trapping mechanism. Mineralization becomes an important trapping mechanism over thousands of years (not shown) post injection.

#### **4.5 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii)**

The Eau Claire Shale will serve as a competent confining zone for the project and supports the demonstration of the alternative PISC timeframe based on the following characteristics:

- It is predicted to be approximately 487 ft thick at the project site,
- It is laterally extensive and extends across Indiana, Ohio, and Illinois, as well as parts of Kentucky,
- It has relatively consistent formation properties (facies, porosity, and permeability) across the region,
- It displays only minor variation in thickness,
- It is not penetrated by any known major faulting.

Based on a CO<sub>2</sub> plume with a maximum radius of 1.69 mi 50 years post injection, the CO<sub>2</sub> plume is only expected to contact an area of the confining zone approximately 8.97 mi<sup>2</sup> in size. Current knowledge of the Eau Claire Shale does not indicate that it will be reactive with the injected CO<sub>2</sub>, and it is not anticipated that prolonged contact with CO<sub>2</sub> will compromise the integrity of the formation. The geomechanical modeling indicates that the pressure exerted on the confining zone within the AoR will not be high enough to compromise the integrity of the formation even if the project were to inject at much higher annual rates (Section 4.4). In the post injection phase of the project, injection zone pressures are predicted to decline quickly and return to pre-injection levels within two years. The risks to confining zone integrity will also decrease significantly as injection zone pressures decrease.

The Project Narrative and the AoR and Corrective Action Plan include further information on the site characterization and computational modeling work that has been completed to support the project (Attachment 1: Narrative, 2022; Attachment 2: AoR and Corrective Action, 2022). As site specific data is collected through the Pre-Operational Testing Program the static and computational modeling will be updated, and the conclusions regarding the confining zone suitability will be verified or re-evaluated.

#### **4.6 Assessment of Fluid Movement Potential – 40 CFR 146.93(c)(1)(viii)-(ix)**

The existing two-dimensional (2D) surface seismic data does not indicate that there are any faults in the immediate area that impact the confining zone (Attachment 1: Narrative, 2022). There are no known artificial penetrations of the confining zone within the project AoR. The closest well (IGWS #144601) that penetrates the Mt. Simon Sandstone is approximately 13 mi to the southwest of the proposed location for CCS1. As a result, no corrective action has been planned for the project. The requirement for corrective action will be re-assessed should the AoR change over the course of the project.

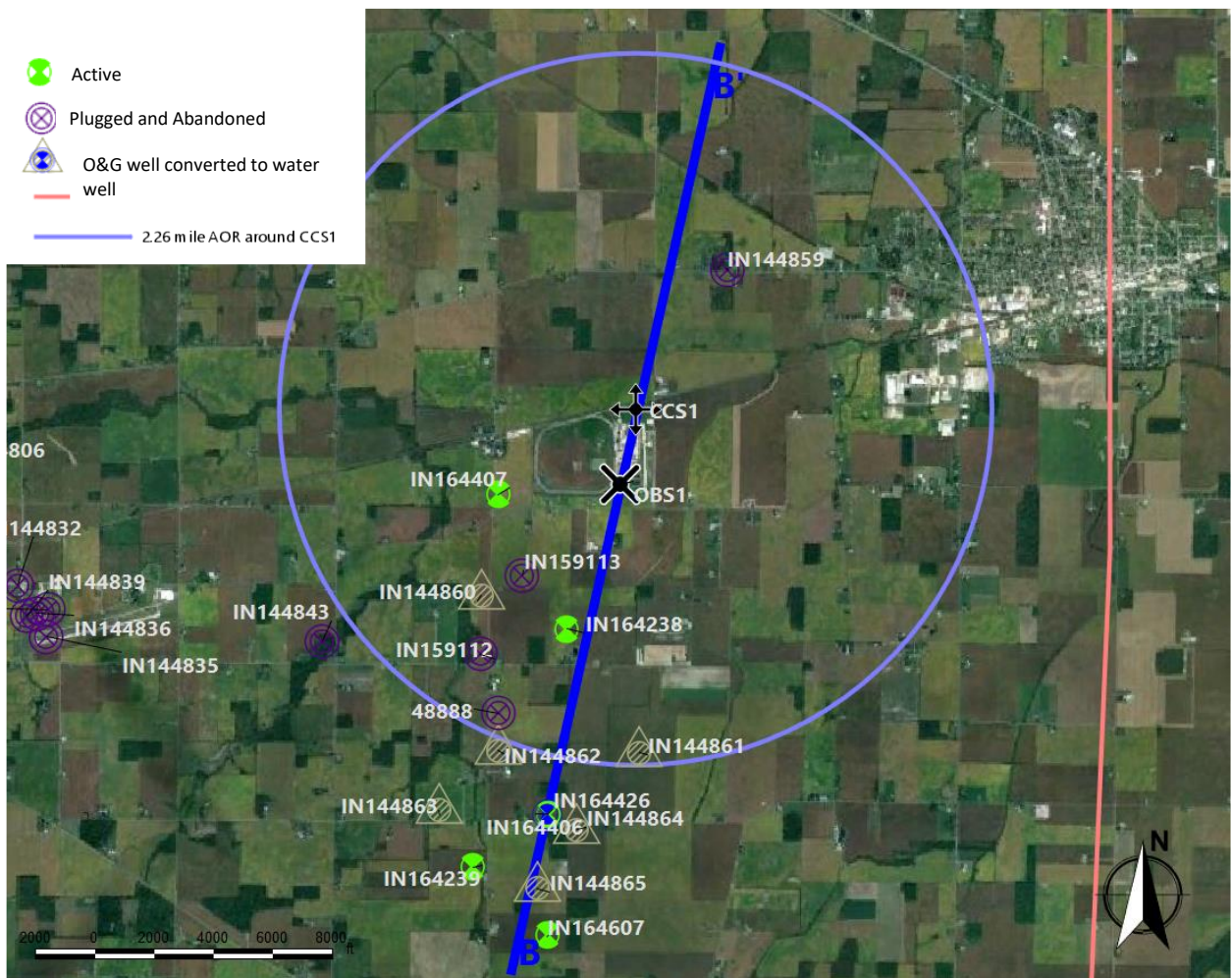
The deepest well (IN144860) is located approximately 1.5 mi southwest from the proposed CCS1 location and reached a depth of 2,310 ft, which is more than 300 feet above the estimated top of the Eau Claire Shale (Figure 8). The Indiana Department of Natural Resources (IDNR) plans to plug this well in 2022. The project plans to monitor the wellhead pressure of ACZ1 and take fluid samples from an ACZ interval within the Knox Formation during the injection and

Plan revision number: N/A

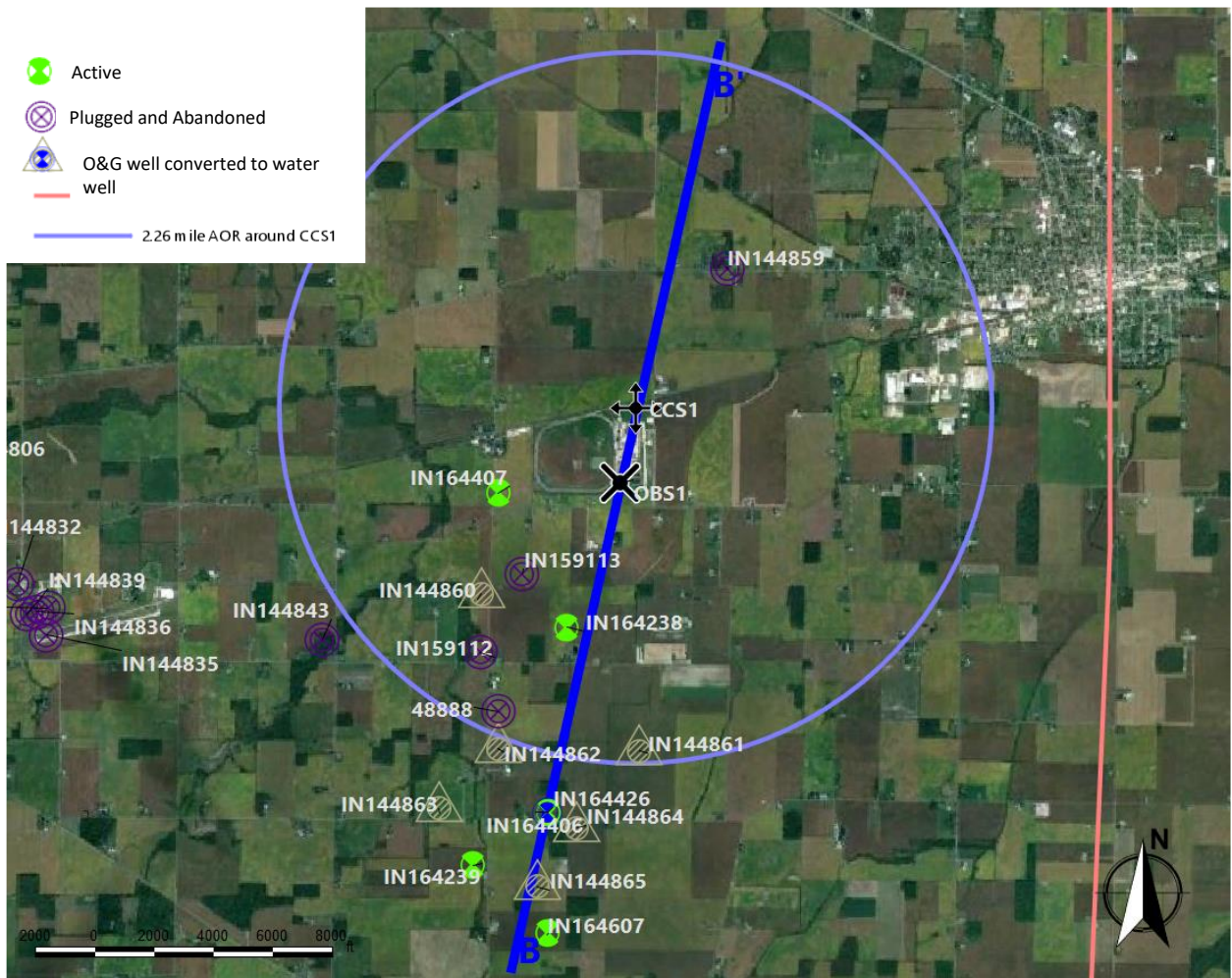
Plan revision date: N/A

PISC phases of the project. If any indicators of injection formation fluids are identified within the ACZ monitoring interval, the project wells will be investigated for any potential well integrity issues. It is expected that any migration of injection zone fluids into the ACZ monitoring interval will be identified before any injection zone fluids can intersect one of the Knox Formation well penetrations.

Figure 9 shows the distribution of shallow groundwater wells in the AoR. The project will continue to monitor a subset of shallow groundwater wells distributed around the for indications that injection zone fluids have migrated past the confining layer during the PISC phase on an annual basis.



**Figure 8: Deep well penetrations within the AoR. The deepest well penetration is IN144860 that reaches a depth of 2,310 ft into the Knox Formation.**



**Figure 9: Shallow groundwater and oil and gas wells that have been converted to groundwater wells in the AoR.**

When CCS1 is drilled and completed, the long string casing will be cemented to surface (Attachment 4: Well Construction, 2022). After cementing is complete, the cement integrity will be evaluated along the length of the well using a cement bond log with radial arms, and an ultrasonic cement evaluation tool will be used to evaluate the cement through the injection zone, confining layer, and ACZ interval (Attachment 5: Pre-Op Testing Program, 2022).

Through the injection phase of the project, the well integrity of CCS1 will regularly be assessed through continuous wellhead pressure (calibrated using downhole pressure measurements), annular pressure and fluid volume, annual mechanical integrity tests, and periodic pressure fall-off tests (Attachment 7: Testing And Monitoring, 2022). During the PISC phase of the project, the well integrity of CCS1 will continue to be monitored through continuous wellhead pressure (and downhole pressure as stipulated in previous sections), and temperature logging every five years (Table 1). PNL will also be used every second year to identify any CO<sub>2</sub> accumulations adjacent to the wellbore in CCS1.

#### **4.7 Location of USDWs – 40 CFR 146.93(c)(1)(x)**

As discussed in detail in the Project Narrative and Financial Assurance sections, the Mt Simon Sandstone is approximately 2,709 feet below the lowermost USDW that is estimated to be at a depth of 450 ft (Attachment 1: Narrative, 2022; Attachment 3: Financial Assurance, 2022). The current estimated depth of the lowermost USDW is based on the 144860 well noted above and IDNR (Attachment 1: Narrative, 2022). Most of the shallow groundwater use in the area occurs at depths between 100 and 250 feet.

During the post injection phase of this project, the vertical extent of injected CO<sub>2</sub> is relatively consistent, and the CO<sub>2</sub> is expected to remain in the injection zone.

#### **5.0 Non-Endangerment Demonstration Criteria**

Prior to approval of the end of the post-injection phase, One Carbon Partnership, LLC (OCP) will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3).

The owner or operator will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

##### **5.1 Introduction and Overview**

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

##### **5.2 Summary of Existing Monitoring Data**

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment (Attachment 7: Testing And Monitoring, 2022). Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

### 5.3 Summary of Computational Modeling History

The computational modeling demonstrates non-endangerment of USDWs in several ways:

- CO<sub>2</sub> plume stabilizes quickly once injection operations cease,
- Injection zone pressures decline rapidly once injection operations cease and will fall below the delta pressure of 227 psi after two years,
- Residual gas and gas solubility trapping of the CO<sub>2</sub> will increase with time and trap the CO<sub>2</sub> more effectively than structural trapping alone
- Geomechanical modeling shows that integrity of the confining layer will be maintained even at much higher annual injection rates.

Table 8 summarizes the monitoring data that will be used to verify and calibrate the computational modeling and support the demonstration of non-endangerment of USDWs.

**Table 8: Summary of monitoring data that will be used to verify and calibrate the computational modeling and support the demonstration of non-endangerment of USDWs**

Monitoring Data	Location	Demonstration of Non-Endangerment
Injection Zone Pressure	CCS1 OBS1	Monitor and verify that injection zone pressures are declining as predicted
PNL	OBS1	Monitor vertical plume development adjacent to OBS1
Time-lapse 3D Surface Seismic Data	Area sufficient to image an 8.97 mi <sup>2</sup> plume	Stabilization of the CO <sub>2</sub> plume once injection operations cease
Microseismic Monitoring	Events within an 8 mi radius of CCS1	Decrease in induced seismic events will demonstrate declining pressures in the injection zone

The monitoring data will be compared predicted properties from the computational model such as vertical and horizontal plume location, rate of movements, and pressure decline. These data will verify that the computational model predictions accurately represent CO<sub>2</sub> and pressure plume behavior and can be used as a proxy for future plume behavior. The monitoring and modeling results will be compared using maps and graphs of the CO<sub>2</sub> and pressure plume development over time. If there is major disagreement between monitoring and modeling results at the time of the demonstration, the models will be updated to reflect the monitoring results.

## **5.4 Evaluation of Reservoir Pressure**

Injection zone pressures will be monitored on a continuous basis in CCS1 and OBS1 (Table 8) until the pressure change is below the critical pressure rise, or after two years, whichever happens later. At that point, static gradient surveys will be performed annually in CCS1. BHP will no longer be monitored in OBS1. Injection zone pressures are predicted to decay below the delta pressure of 227 psi in the first two years after injection operations cease. Pressure decreases predicted by the model can be compared to the monitor data at regular intervals to verify and calibrate the model during the PISC phase.

If microseismic events are generated because of the CO<sub>2</sub> injection operations, it is expected that the rate of the events generated will decrease as injection zone pressure decreases. The rate of microseismic activity will provide further qualitative information about the decrease in pressure throughout the injection zone during the PISC phase.

Increased pressure in the injection zone is one of the main drivers for fluid migration through the confining layer through conduits such as well penetrations. As the injection zone pressure decreases during the PISC phase so too will the risk of fluid migration out of the injection zone and the potential risk to USDWs.

## **5.5 Evaluation of CO<sub>2</sub> Plume**

Table 8 summarizes the monitoring data that will be used to evaluate the extent of the CO<sub>2</sub> plume every second year starting in Year 1 of the PISC phase. PNL logging will be used to monitor the distribution and saturation of CO<sub>2</sub> adjacent to the wellbore OBS1. In CCS1, it is expected that the near wellbore zone will be saturated with CO<sub>2</sub> and the plume will take up the entire injection zone, so there will be little value in running the PNL through the injection zone. However, the PNL will be run through the ACZ monitoring zone to verify that there are no accumulations of CO<sub>2</sub> adjacent to the wellbore above the confining layer in CCS1.

The time-lapse 3D surface seismic data will be acquired in Year 0 and Year 8 of the PISC phase. Data from these surveys will be used demonstrate the stabilization of the CO<sub>2</sub> plume predicted by the computational modeling once injection ceases. The data will also be used to confirm the continued absence of any accumulations of CO<sub>2</sub> above the confining zone within the AoR.

## **5.6 Evaluation of Emergencies or Other Events**

Table 9 provides a summary of the monitoring data that will be used to demonstrate that injection zone fluids have not migrated above the confining layer; this includes CO<sub>2</sub> or brines. Data acquired through the injection and PISC phases of the project will be compared to the baseline data gathered for the project to ensure that there are no indications that injection zone fluids have migrated into the ACZ monitoring interval or to the lowermost USDW. If the PISC monitoring data shows no significant changes from the baseline data, it will demonstrate the integrity of the confining layer and that injection zone fluids are not an endangerment to USDWs.

**Table 9: Summary of monitoring data that will be used to demonstrate of non-endangerment of USDWs above the confining zone**

Monitoring Data	Location	Demonstration of Non-Endangerment
ACZ Pressure	ACZ1	<ul style="list-style-type: none"> <li>No pressure increases that could indicate fluid migration out of injection zone</li> </ul>
ACZ Fluid Sampling	ACZ1	<ul style="list-style-type: none"> <li>No geochemical indicators of fluid migration out of injection zone</li> <li>Includes changes to salinity</li> </ul>
Lowermost USDW Fluid Sampling	USDW1	<ul style="list-style-type: none"> <li>No geochemical indicators of fluid migration out of injection zone</li> </ul>
Temperature Logging	CCS1 OBS1	<ul style="list-style-type: none"> <li>No CO<sub>2</sub> migration along the wellbores</li> </ul>
PNL	CCS1 OBS1	<ul style="list-style-type: none"> <li>No CO<sub>2</sub> accumulations adjacent to wellbores</li> <li>No increase in salinity adjacent to wellbores</li> </ul>
Time-lapse 3D Surface Seismic Data	Area sufficient to image an 8.97 mi <sup>2</sup> plume	<ul style="list-style-type: none"> <li>Verify the absence of CO<sub>2</sub> accumulations</li> </ul>
Microseismic Monitoring	Events within an 8 mi radius of CCS1	<ul style="list-style-type: none"> <li>Monitor for microseismic events in the confining layer that might indicate issues with confining zone integrity</li> </ul>

The closest artificial penetration to the project wells in the injection zone is N14601 that is approximately 13 mi to the southwest. The maximum extent of the CO<sub>2</sub> and pressure plumes is predicted to be 1.69 mi over the life of the project, so the closest well will still be approximately 11.31 mi away from the maximum plume extents. No other conduits for fluid flow beyond the confining layer have been identified in the AoR at this time.

The well integrity of the CCS1 will be thoroughly assessed during the Pre-Operational Testing Program using Cement Bond Logs and Variably Density Logs (CBL-VDL) as well as ultrasonic cement evaluation tools that will be run specifically over the injection zone, confining layer, and ACZ monitoring interval (Attachment 5: Pre-Op Testing Program, 2022).

During the injection phase, the well integrity of CCS1 will be continuously monitored using wellhead pressure gauges and annular pressure and fluid volume levels for any indications that there may be problems (Attachment 7: Testing And Monitoring, 2022). Wellhead and downhole pressures will continue be monitored in CCS1 during the PISC phase. The project will continue to run temperature logs at a maximum of every five years, and PNL logs every second year starting in Year 1 to ensure that CCS1 and OBS1 are not providing a conduit for injection zone fluids to migrate above the confining layer.

The Emergency and Remedial Response Plan (ERRP) includes further discussion of how emergencies or other events will be addressed by the project (Attachment 10: ERRP, 2022).

## **6.0 Site Closure Plan**

OCP will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Cardinal Ethanol will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, OCP will plug the monitoring wells and submit a site closure report to EPA. The activities, as described below, represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

### **6.1 Plugging Monitoring Wells**

As discussed in the testing and monitoring section of the application, there will be several dedicated monitoring wells. Of those presented in the section, the OBS1 and ACZ1 wells will be plugged as part of the site closure process.

This subsection serves to provide the methods and procedures that will be utilized to plug each of the wells. In addition to discussing the methodology and procedures to be utilized, schematics displaying the anticipated layout of the well following completion of the plugging and abandonment (P&A) operations are provided. The cost estimates developed for these activities are provided in the Financial Assurance section of this application.

#### **6.1.1 OBS1 Plugging and Abandonment**

The techniques used to P&A OBS1 will be similar to those applied to the CCS1 well, as discussed in the P&A section for the injection well (Attachment 8: Well Plugging, 2022). CO<sub>2</sub> resistant cement will be placed from the bottom of the well, to above the confining zone, then normal cement will be placed above that.

Cement volumes are anticipated to be lower than those used for the injection well as OBS1 will use smaller sized tubulars. The cement volumes to be used to P&A the OBS1 well will be finalized following the installation of the well.

A figure displaying the proposed P&A schematic for OBS1 is provided in Figure 10.

Plan revision number: N/A

Plan revision date: N/A

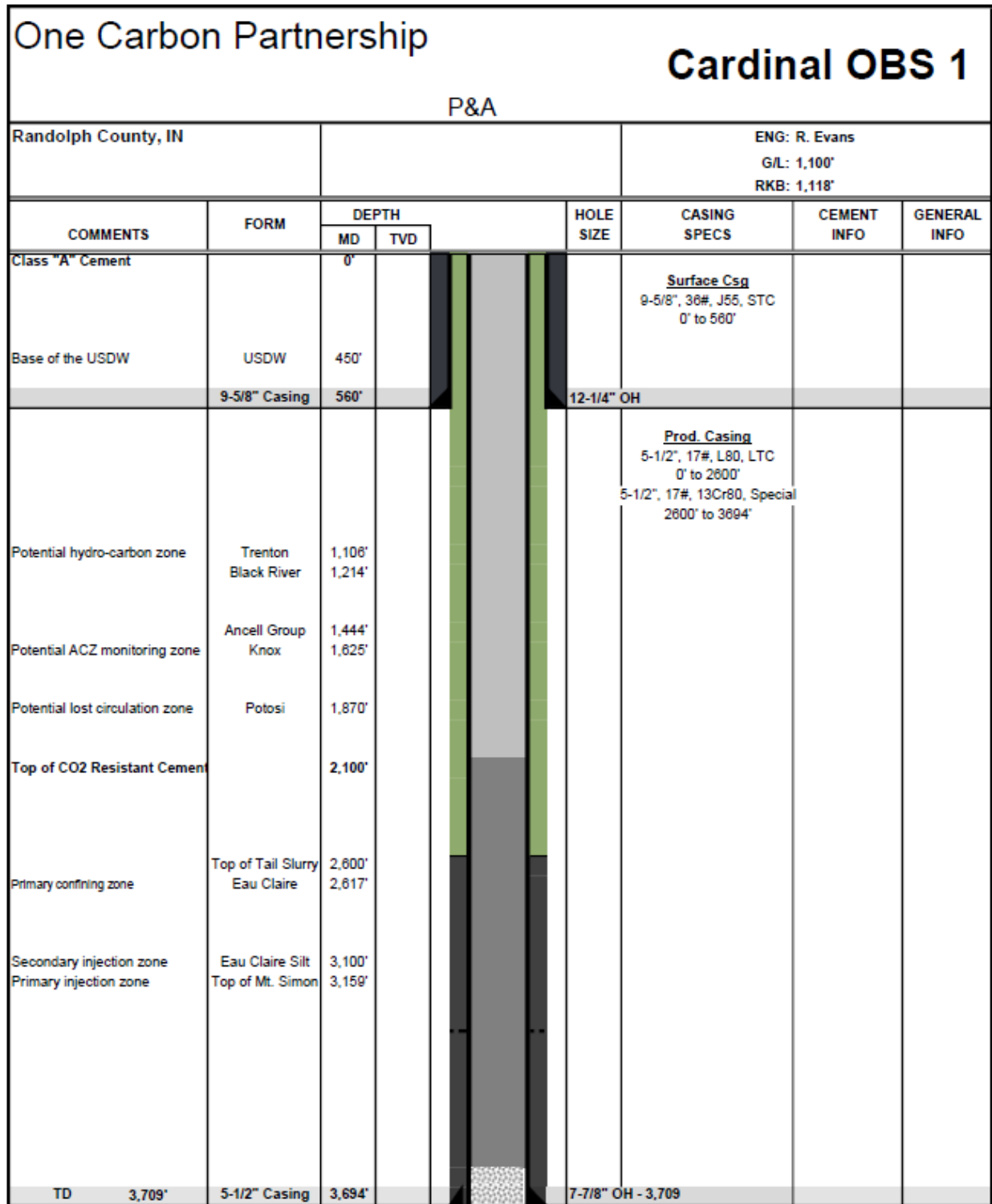


Figure 10. OBS1 Well Plugging and Abandonment Schematic

Plan revision number: N/A

Plan revision date: N/A

### ***6.1.2 ACZ1 Plugging and Abandonment***

The techniques used to P&A ACZ1 will be similar to those applied to OBS1 and CCS1 above the confining zone (Attachment 8: Well Plugging, 2022). Normal cement will be placed from the bottom of the well to surface.

Cement volumes are anticipated to be lower than those used for the injection well as ACZ1 will use smaller sized tubulars. The cement volumes to be used to P&A the ACZ1 well will be finalized following the installation of the well.

A figure displaying the P&A schematic for ACZ1 is provided in Figure 11.

Plan revision number: N/A

Plan revision date: N/A

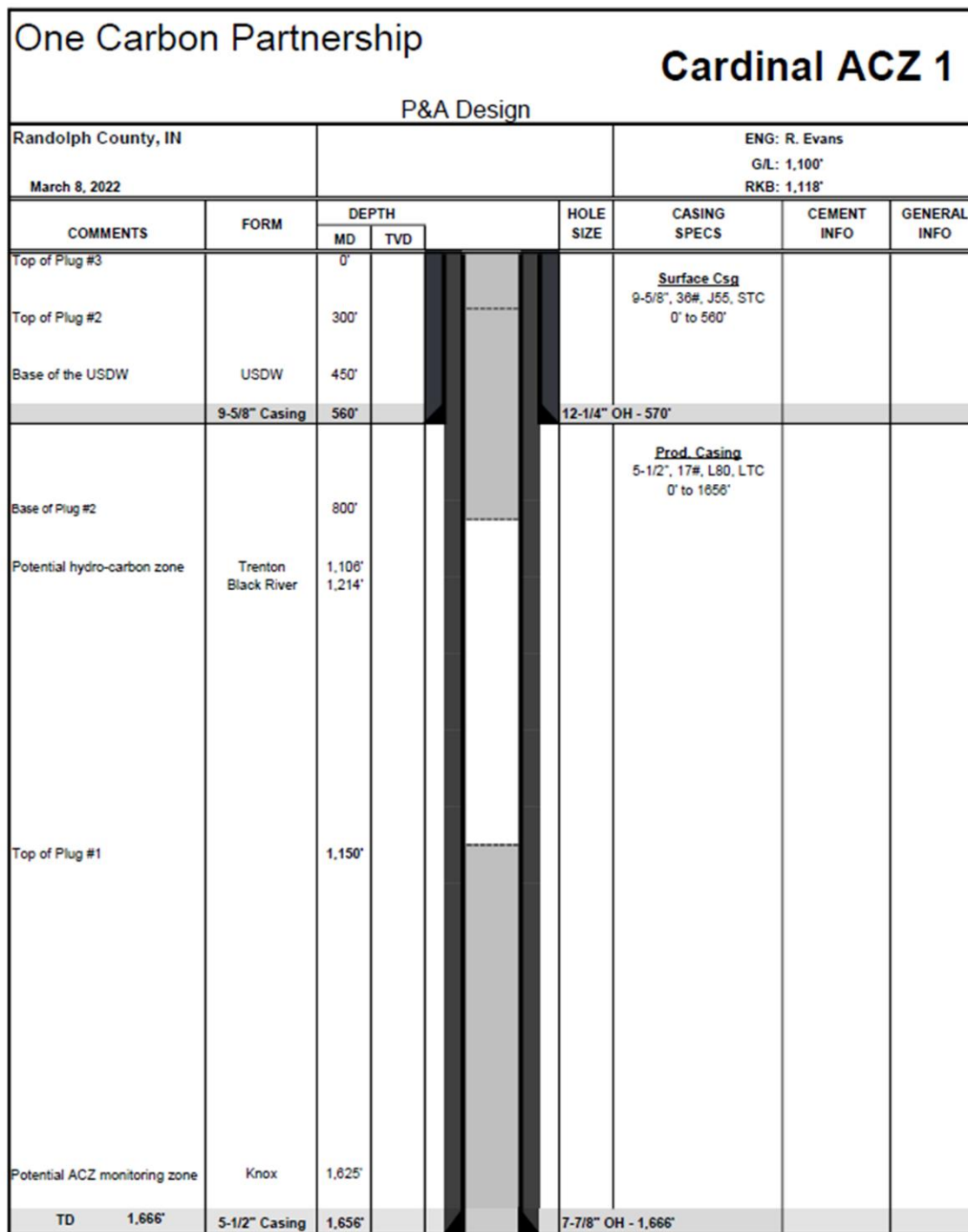


Figure 11: ACZ1 Well Plugging and Abandonment Schema

Plan revision number: N/A

Plan revision date: N/A

## **6.2 Site Closure Report**

In accordance with 40 CFR 146.93(f), a site closure report will be prepared and submitted within 90 days following site closure, documenting the information required by 40 CFR 146.93(f), as applicable, including but not limited to the following:

- Plugging of the verification and geophysical wells (and the CCS1 if it has not previously been plugged),
- Location of sealed CCS1 on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO<sub>2</sub>, and
- Post-injection monitoring records.

In accordance with 40 CFR 146.93(g), OCP will record in the real property records of the county where the project is located notice of the property tracts integrated for the storage facility and proper notice of the CCS1 well that will include the following:

- That the property was used for CO<sub>2</sub> sequestration,
- The name of the local (state, federal, etc.) agency to which a plat of survey with CCS1 location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

In accordance with 40 CFR 146.93(h), the site closure report will be submitted to the permitting agency (EPA) and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

## **6.3 Quality Assurance and Surveillance Plan**

The Quality Assurance and Surveillance Plan is presented in (Attachment 11: QASP, 2022).

Plan revision number: N/A

Plan revision date: N/A

## **References**

- (2022). *Attachment 1: Narrative*. Class VI Permit Application Narrative; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 10: ERRP*. Emergency And Remedial Response Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 11: QASP*. Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 2: AoR and Corrective Action*. Area Of Review And Corrective Action Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 3: Financial Assurance*. Financial Responsibility; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 4: Well Construction*. Injection Well Construction Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 5: Pre-Op Testing Program*. Pre-Operational Formation Testing Program; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 6: Well Operations*. Well Operation Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 7: Testing And Monitoring*. Testing And Monitoring Plan; Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 8: Well Plugging*. Hoosier#1 Project, Vault 4401.
- (2022). *Attachment 9: Post-Injection Site Care*. Post-Injection Site Care And Site Closure Plan; Hoosier#1 Project, Vault 4401.

**ATTACHMENT 10: EMERGENCY AND REMEDIAL RESPONSE PLAN**  
**40 CFR 146.94(a)**  
**PROJECT HOOSIER #1**

**Facility Information**

Project Name: Hoosier #1

Facility Name: Cardinal Ethanol

Facility Contact: Jeremey Herlyn, Project Manager  
Cardinal Ethanol

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
CO<sub>2</sub> Injection Well Location for Cardinal CCS1  
Latitude 40.186587°  
Longitude -84.864284°

Operator: One Carbon Partnership, LP  
1554 N. 600 E.  
Union City, IN 47390

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## **List of Acronyms**

AoR	Area of Review
CCS1	Proposed Injection Well
CO <sub>2</sub>	Carbon Dioxide
ERRP	Emergency and Remedial Response Plan
OBS1	Deep Observation Well
OCP	One Carbon Partnership, LP
SOP	Standard Operating Procedure
USDW	Underground Source of Drinking Water

## 1 Introduction

This section of the permit application addresses the Emergency Remedial and Response Plan (ERRP) that One Carbon Partnership, LP (hereafter referred to as OCP) will implement for the Hoosier #1 Project. This ERRP describes the actions that OCP shall take to address and remediate mechanical integrity issues, seismic events, and other events that could allow for the movement of the injected fluid or formation brine in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The following events are identified as potential risk scenarios. These scenarios are discussed further in Section 2. These scenarios were identified and discussed as part of the Risk Assessment performed for the project.

1. Proposed Injection Well (CCS1)/Deep Observation Well (OBS1) well integrity failure,
2. CCS1/OBS1 monitoring equipment failure,
3. Natural Disaster,
4. Fluid (non-CO<sub>2</sub>) leakage into a USDW or surface,
5. CO<sub>2</sub> leakage into USDW or surface,
6. Induced seismic event.

In accordance with 40 CFR 146.94 (b), should OCP obtain evidence that the injected CO<sub>2</sub> stream and/or associated pressure front may cause an endangerment to a USDW, OCP must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase “initiate shutdown plan” is used, the following protocol will be employed: OCP will immediately cease injection. However, in some circumstances, OCP will, in consultation with the UIC Program Director, determine whether gradual cessation of injection is appropriate.

## **2 Local Resources and Infrastructure**

Resources in the Area of Review (AoR) of the project that may be affected as a result of an emergency event at the project site include the shallow and lowermost USDWs as discussed in (Attachment 1: Project Narrative, 2022).

These include:

- Unconsolidated glacial till
  - New Castle Till Aquifer
  - Bluffton Till Aquifer
- Maquoketa Shale

In addition to these local aquifers, several surface bodies of water are also located within the AoR. These include:

- Shelley Ditch,
- Shelly Ditch,
- Price Ditch,
- Little Ditch,
- White River,
- Owl Creek,
- Little Mississinewa River,
- Several small unnamed reservoirs.

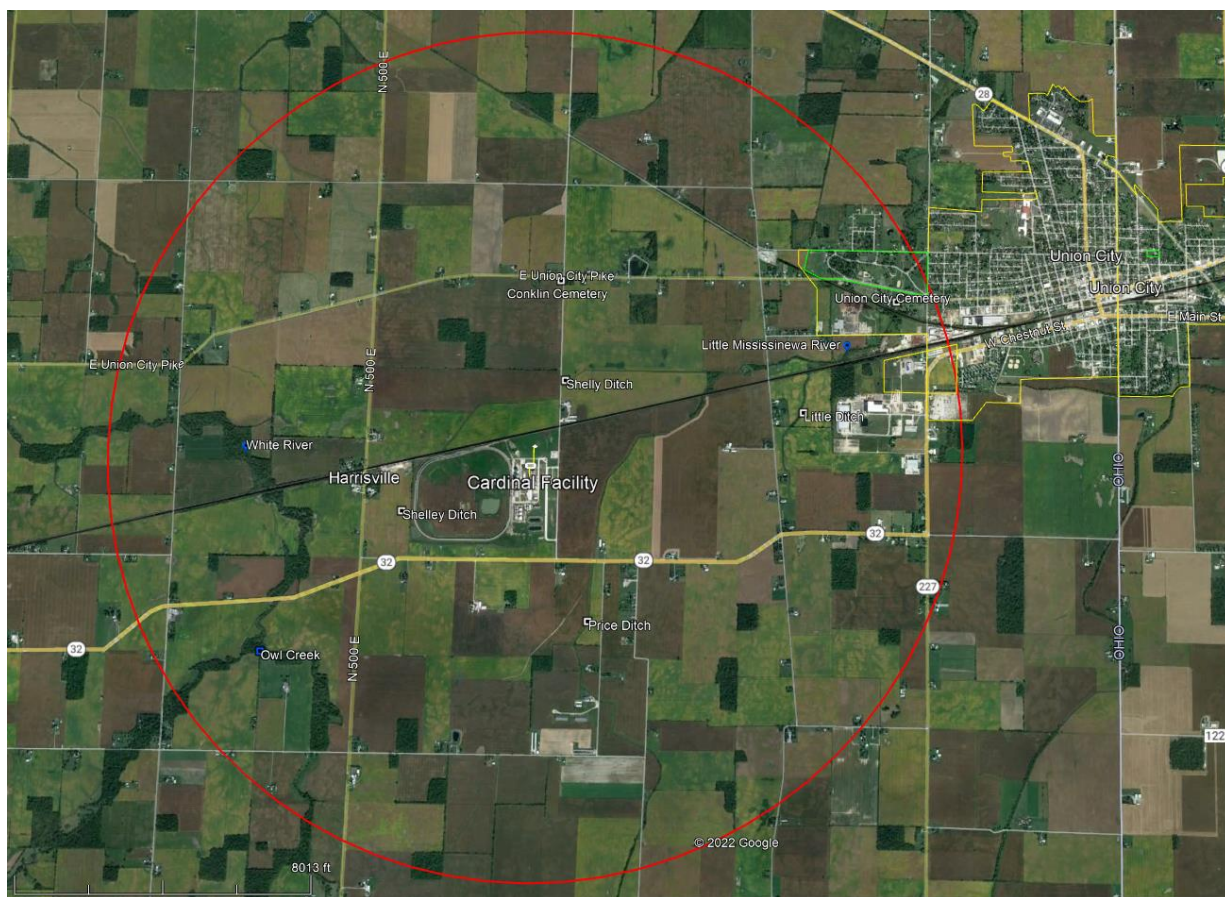
Population centers and towns in the vicinity of the project that that may be affected as a result of an emergency at the project site include:

- Harrisville
- Portions of Union City
- Wayne Township

The Union City Water Treatment facilities lie outside of the AoR (approximately 0.75 and 0.80 miles to the East). Major public infrastructure (parks, cemeteries, etc.) within the AoR includes:

- Harter Park
- Union City Swimming Pool
- Union City Cemetery
- Conklin Cemetery

Resources and infrastructure addressed in this plan are shown in Figure 1.



**Figure 1. Map of the site resources and infrastructure.**

### 3 Potential Risk Scenarios

The following events related to the project, as listed in Section 1, could potentially result in an emergency response:

- CCS1/OBS1 well integrity failure,
- Natural Disaster,
- Fluid (non-CO<sub>2</sub>) leakage into a USDW
- CO<sub>2</sub> leakage into USDW,
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. “Emergency events” are categorized as shown in Table 1.

Additional events have also been considered, but were accounted for in other sections, are not anticipated to occur, or will be accounted for without a formal plan.

- Unanticipated emergency corrective action(s) needed on a well within the AoR
  - The ramifications of this have been addressed in the Financial Assurance section (Attachment 3: Financial Responsibility, 2022).
  - Corrective action will be performed on an as needed basis. These actions will likely vary by situation. Response actions, prior to corrective action, will likely be the same as those applied to a CO<sub>2</sub> or non-CO<sub>2</sub> leak into an aquifer.
- CO<sub>2</sub> exposure in capture or sequestration facility
  - Air quality monitors will be installed in enclosed spaces. Fans meant to remove the CO<sub>2</sub> from these spaces will be activated if the CO<sub>2</sub> rises above permissible exposure limits.
- Metal leaching due to prolonged wetted CO<sub>2</sub> exposure
  - Materials of construction confirmed to be suitable for long term corrosive loading will be utilized for this project

**Table 1. Degrees of risk for emergency events.**

<b>Emergency Condition</b>	<b>Definition</b>
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

In addition to these scenarios, CCS1/OBS1 monitoring equipment failure has also been identified as a risk that is planned for, but may not require anything more than a remedial response.

## 4 Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Once equipment placement and location is finalized, a figure will be provided that displays the following:

- Major facility components,
- Project wells,
- Monitoring equipment,
- Emergency shut-down equipment, and
- Flowlines.

It is important to note that in major or serious events, certain actions may be taken to minimize the impact of such events before they are listed in the following action plans. Additionally, as part of the minimization of these events, emergency services may be contacted prior to any other actions taking place.

Within this section, several mentions are made to evacuation plans. A formal evacuation plan will be provided as part of the final ERRP. Different evacuation plans will be provided for each of the following groups:

- Non-key site personnel
- Key site personnel
- Offsite personnel

In addition, primary and secondary muster points will be provided for each of these groups. This plan will be integrated with the current Cardinal facility evacuation plan. These plans will be provided as part of operator training and dispersed throughout the facility.

In the event an emergency requires evacuating a separate part of the Cardinal facility, the well will be shut-in and secured as quickly and as safely possible.

### 4.1 Well Integrity Failure (CCS1 or OBS1)

Integrity loss of the injection well and/or verification well may endanger USDWs. Integrity loss may have occurred if the following events occur (note, this is not an exhaustive list):

- Automatic shutdown devices are activated:
  - *Wellhead pressure* exceeds the maximum allowed injection pressure.
    - Note: high-high pressure limit will be set to 5% less than the maximum allowed injection pressure in the permit.
  - *Bottomhole flowing pressure* exceeds the maximum allowable bottom hole flowing pressure as calculated from the wellhead pressure.
    - Note: high-high pressure limit will be 5% less than the maximum allowed bottomhole pressure detailed in the permit.
  - *Annulus pressure* indicates a loss of external or internal well containment
    - The emergency shutdown points (as discussed in the Testing and Monitoring Section and Well Operations Section of this application) of -5 or 1,500 psi are exceeded.

- Note: pursuant to 40 CFR 146.94(b)(3), OCP must notify the UIC Program Director within 24 hours of any triggering of an emergency shutdown system.
- Mechanical integrity test results identify a loss of mechanical integrity.
  - Note: pursuant to 40 CFR 146.94(b)(3), OCP must notify the UIC Program Director within 24 hours of a loss of mechanical integrity that could lead to endangerment of the USDW.

Response actions:

1. Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.94(b)(3).
2. Determine the severity of the event, based on the information available, within 24 hours of notification.
  - a. For a Major or Serious emergency:
    - i. Initiate shutdown plan.
      1. Shut-in the well
        - a. All necessary valves closed and locked out
      2. Vent CO<sub>2</sub> from surface lines and facility as necessary
      3. Limit access to wellhead and surface facilities to only those authorized
        - a. Caution tape and/or rope may be used to limit access to the well and facility
      4. Initiate evacuation plans (if necessary)
        - a. Communicate at all times with Cardinal personnel and local authorities if evacuation is necessary
      5. Monitor wellhead pressure (tubing and annulus) and temperature as is feasible.
        - a. This information should be used to assess the nature and extent of the mechanical integrity failure
      6. Identify appropriate remedial actions to repair damage to the well
    - ii. If contamination is detected, identify and implement appropriate remedial actions.
      1. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
    - iii. Perform mechanical integrity test prior to bringing the well back online.
  - b. For a Minor emergency:
    - i. Assess the well to determine whether there has been a loss of mechanical integrity.
    - ii. If a loss of mechanical integrity is present, initiate the shutdown plan.
      1. Shut-in the well
        - a. All necessary valves closed and locked out
      2. Vent CO<sub>2</sub> from surface lines and facility as necessary
      3. Limit access to wellhead and surface facilities to only those authorized

- a. Caution tape and/or rope may be used to limit access to the well and facility
4. Reset automatic shutdown devices
5. Monitor wellhead pressure (tubing and annulus) and temperature as is feasible.
  - a. This information should be used to assess the nature and extent of the mechanical integrity failure
6. Identify appropriate remedial actions to repair damage to the well.
- iii. If contamination is detected, identify and implement appropriate remedial actions.
  1. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
- iv. Perform mechanical integrity test prior to bringing the well back online.

#### **4.2 Well Monitoring Equipment Failure (CCS1 or OBS1)**

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

This subsection covers the remedial response and procedures to be followed should one (or more) of the following monitoring sensors fail:

- Injection Well (CCS1)
  - Wellhead injection pressure
  - Wellhead injection temperature
  - Annulus pressure
  - Annulus fluid volume
  - Injection flowrate
- Deep Observation Well (OBS1)
  - Annulus pressure
  - Annulus fluid volume

Response actions:

1. Determine the impact of the event, based on the information available, within 24 hours of the event occurring. At this time, the impact of the loss of monitoring equipment should be assessed, and a viable alternative method should be determined and implemented.
  - a. Assess the well to determine whether there has been a loss of mechanical integrity associated with the failure of a piece of monitoring equipment.
  - b. If a loss of mechanical integrity is not present, assess the impact the loss of monitoring equipment could have on operations.
    - i. If the impact is negligible, implement the viable alternative method of monitoring determined during the initial assessment.
    - ii. Plans to replace the equipment should consider replacing the equipment as soon as is feasible based on operational conditions and suitability of the alternative method of monitoring.

- iii. Provide details of the equipment failure, the alternative method of monitoring, and impact to continuous data collection to the UIC Program Director as part of the routine operational reporting.
- c. If a loss of mechanical integrity is present, initiate the shutdown plan.
  - i. Notify the UIC Program Director within 24 hours of the event, per 40 CFR 146.94(b)(3)
  - ii. Shut-in the well
    - 1. All necessary valves closed and locked out
  - iii. Vent CO<sub>2</sub> from surface lines and facility as necessary
  - iv. Limit access to wellhead and surface facilities to only those authorized
    - 1. Caution tape and/or rope may be used to limit access to the well and facility
  - v. Reset automatic shutdown devices
  - vi. Monitor wellhead pressure (tubing and annulus) and temperature as is feasible.
    - 1. This information should be used to assess the nature and extent of the mechanical integrity failure
    - 2. Note that alternative methods of monitoring may need to be implemented at this time.
  - vii. Identify appropriate remedial actions to repair damage to the well.
  - viii. If contamination is detected, identify and implement appropriate remedial actions.
    - 1. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
  - ix. Perform mechanical integrity test prior to bringing the well back online.

### 4.3 Natural Disaster

Disturbance or damage as a result of a natural disaster may impact the normal operation of the project. A non-exhaustive list of examples of such potential events and the impact to the project they may cause are:

- An earthquake damages compression equipment and causes an integrity issue with the CO<sub>2</sub> flowline,
- Lightning strikes the wellhead and damages all surface monitoring equipment,
- Severe flooding (i.e., 100-year flood) limits access to the well or injection facility.

These events may impact or damage the ability to properly operate the well or utilize the facility for the intended purposes of the project.

If a natural disaster occurs that affects normal operation of the injection well, perform the following:

Response actions:

1. Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.94(b)(3).
2. Determine the severity of the event, based on the information available, within 24 hours of notification.
  - a. For a Major or Serious emergency:
    - i. Initiate shutdown plan.
      1. Shut-in the well
        - a. All necessary valves closed and locked out
      2. Vent CO<sub>2</sub> from surface lines and facility as necessary
      3. Limit access to wellhead and surface facilities to only those authorized
        - a. Caution tape and/or rope may be used to limit access to the well and facility
      4. Initiate evacuation plans (if necessary)
        - a. Communicate at all times with Cardinal personnel and local authorities if evacuation is necessary
      5. Monitor wellhead pressure (tubing and annulus) and temperature as is feasible.
        - a. This information should be used to assess the nature and extent of the mechanical integrity failure
      6. Identify appropriate remedial actions to repair damage to the well
    - ii. Determine if any leaks of fluid have occurred due to the natural disaster
      1. If contamination is detected, identify and implement appropriate remedial actions.
      2. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
    - iii. Perform mechanical integrity test prior to bringing the well back online.
  - b. For a Minor emergency:
    - i. Assess the well to determine whether there has been a loss of mechanical integrity.
    - ii. If a loss of mechanical integrity is present, initiate the shutdown plan.
      1. Shut-in the well
        - a. All necessary valves closed and locked out
      2. Vent CO<sub>2</sub> from surface lines and facility as necessary
      3. Limit access to wellhead and surface facilities to only those authorized
        - a. Caution tape and/or rope may be used to limit access to the well and facility
      4. Reset automatic shutdown devices
      5. Monitor wellhead pressure (tubing and annulus) and temperature as is feasible.
        - a. This information should be used to assess the nature and extent of the mechanical integrity failure

6. Identify appropriate remedial actions to repair damage to the well.
- iii. Determine if any leaks of fluid have occurred due to the natural disaster
  1. If contamination is detected, identify and implement appropriate remedial actions.
  2. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
- iv. Perform mechanical integrity test prior to bringing the well back online.

#### **4.4 Non CO<sub>2</sub> (Brine) Fluid Leakage into USDW or Surface**

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) leakage into a USDW.

Response actions:

1. Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.94(b)(3).
2. Determine the severity of the event, based on the information available, within 24 hours of notification.
3. For all emergencies (Major, Serious, or Minor):
  - a. Shut-in the well
    - i. All necessary valves closed and locked out
  - b. Vent CO<sub>2</sub> from surface lines and facility as necessary
  - c. Collect confirmation sample(s) of groundwater and perform groundwater constituent analysis to determine elevated parameters
    - i. The parameters to be tested are provided in the testing and monitoring plan (Attachment 7: Testing And Monitoring, 2022).
    - ii. If the presence of indicator parameters are confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
      1. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
  - d. The following plan of action may be initiated should drinking water be negatively impacted:
    - i. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
  - e. Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by OCP and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

#### **4.5 CO<sub>2</sub> Leakage into USDW or Surface**

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of CO<sub>2</sub> leakage into a USDW.

Response actions:

1. Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.94(b)(3).
2. Determine the severity of the event, based on the information available, within 24 hours of notification.
3. For all emergencies (Major, Serious, or Minor):
  - a. Shut-in the well
    - i. All ball valves closed and locked out
  - b. Vent CO<sub>2</sub> from surface lines and facility as necessary
  - c. Collect confirmation sample(s) of groundwater and perform routine analysis to determine elevated parameters
    - i. The parameters to be tested are provided in the testing and monitoring plan.
    - ii. If the presence of indicator parameters are confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
      1. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
  - d. The following plan of action may be initiated should drinking water be negatively impacted:
    - i. Potential actions are listed in the ERR portion Financial Assurance section of this application, and are dependent on the magnitude of any potential contamination (Attachment 3: Financial Responsibility, 2022).
  - e. Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by OCP and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

#### **4.6 Induced Seismic Event**

Induced seismic events typically refer to minor seismic events that are caused by human activity. These events are typically caused when activity alters the stresses or fluid pressures in subsurface formations. This alteration of fluid pressures and stresses could potentially be caused by the injection of fluids. This change in stress can cause fault movement and energy release. This energy release results in seismic events.

It is not expected that natural seismicity will affect the project. The Illinois Basin – Decatur Project (IBDP) injected CO<sub>2</sub> into the basal section of the Mt. Simon Sandstone, and generated microseismic events throughout the injection phase of the project despite injecting CO<sub>2</sub> below fracture pressure (Bauer, 2016). This project plans to inject above the basal section of the Mt.

Simon Sandstone and will monitor related microseismic activity to assist in managing project risks (Attachment 12: Confidential Business Information: Risk Register, 2022). The microseismic monitoring will be used to accurately determine the locations and magnitudes of injection-induced seismic events with the primary goals of:

- Addressing public and stakeholder concerns related to induced seismicity
- Monitoring the spatial extent of the pressure front from the distribution of seismic events
- Identifying activity that may indicate failure of the confining zone and possible containment loss

A surface-based microseismic monitoring array will be designed with microseismic monitoring stations at a range of azimuths to optimize the accuracy of the event locations and magnitudes. This network can easily be expanded in response to monitoring results or future AoR re-evaluations, if necessary.

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel with information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

**Table 2. Seismic monitoring system, for seismic events > M1.0 with an epicenter within an 8 mile radius of the injection well.**

Operating State	Threshold Condition <sup>1,2</sup>	Response Action <sup>3</sup>
<b>Green</b>	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels.
<b>Yellow</b>	Five (5) or more seismic events within a 30 day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the event, notify the UIC Program Director of the operating status of the well.
<b>Orange</b>	Seismic event greater than M1.5 and local observation or felt report	1. Continue normal operation within permitted levels. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.
	Seismic event greater than M2.0 and no felt report	3. Review seismic and operational data. 4. Report findings to the UIC Program Director and issue corrective actions, if necessary.
<b>Magenta</b>	Seismic event greater than M2.0 and local observation or report	1. Initiate rate reduction plan. 2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 5. Determine if leaks to ground water or surface water occurred (CO <sub>2</sub> or brine). 6. If USDW contamination is detected: a. Notify the UIC Program Director within 24 hours of the determination. b. Follow plan of action as detailed in Sections 4.4 and 4.5. 7. Review seismic and operational data. 8. Report findings to the UIC Program Director and issue corrective actions, if necessary.

<sup>1</sup> Specified magnitudes refer to magnitudes determined by local seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

<sup>2</sup> “Felt report” and “local observation and report” refer to events confirmed by local reports of felt ground motion or reported on the USGS “Did You Feel It?” reporting system.

<sup>3</sup> Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition <sup>1,2</sup>	Response Action <sup>3</sup>
<b>Red</b>	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage <sup>4</sup>	<ol style="list-style-type: none"> <li>1. Initiate shutdown plan.</li> <li>2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.</li> <li>3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.</li> <li>4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).</li> <li>5. Determine if leaks to groundwater or surface water occurred.</li> <li>6. If USDW contamination is detected: <ol style="list-style-type: none"> <li>a. Notify the UIC Program Director within 24 hours of the determination.</li> <li>b. Follow plan of action as detailed in Section 4.4 and 4.5.</li> </ol> </li> <li>7. Review seismic and operational data.</li> <li>8. Report findings to the UIC Program Director and issue corrective actions, if necessary.</li> </ol>
	Seismic event >M3.5	

#### 4.7 Unforeseen Events

Should unforeseen events occur (i.e., meteor strike, global pandemic, etc.) that could impact the operations and integrity of the program, response steps will be provided to the UIC Program Director and implemented once approved.

<sup>1</sup> Specified magnitudes refer to magnitudes determined by local seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

<sup>2</sup> “Felt report” and “local observation and report” refer to events confirmed by local reports of felt ground motion or reported on the USGS “Did You Feel It?” reporting system.

<sup>3</sup> Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

<sup>4</sup> Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

## 5 Response Personnel, Authorities, and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP. The injection well and non-shallow aquifer monitoring wells are located on Cardinal property. Offsite monitoring of shallow groundwater will occur at various points throughout the cities listed in Section 2. As such, local responders for these places will be utilized for emergency contacts and will be notified of an incident as necessary. In addition, state agencies may need to be notified as well.

Site personnel to be notified (not listed in order of notification):

1. Project Engineer(s)
2. Plant Safety Manager(s)
3. Environmental Manager(s)
4. Plant Manager
5. Plant Superintendent

All staff will be trained in the methods prescribed in Section 8 of this document.

A site-specific emergency contact list will be developed, maintained and periodically updated during the life of the project. The list will include phone numbers and email addresses for facility emergency 24-hour contacts. OCP will provide the current site-specific emergency contact list to the UIC Program Director prior to commencement of injection operations.

**Table 3. Contact information for key local, state, and other authorities.**

Agency	Phone Number
Union City Police Department	765-964-5353
Union City Fire & EMS	765-964-4488 (Indiana) 937-968-5605 (Ohio)
Randolph County Sheriff	765-584-1721
Indiana State Police	765-778-2121
Indiana Emergency Management and Preparedness Division	765-584-1721 (Local)
Environmental services contractor	516-333-4526 (RTP – Environmental Consultant) 260-489-7062 (ERS – Emergency Spill Response)
UIC Program Director (Region 5)	312-353-7648
EPA National Response Center (24 hours)	800-424-8802
Indiana DNR	317-232-4200

Equipment needed in the event of an emergency and remedial response will vary, depending upon the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a workover rig or logging equipment) is required, OPC shall be responsible for its procurement.

## 6 Emergency Communications Plan

The order of contact when an emergency occurs is the following:

1. Plant Manager,
2. Necessary emergency authorities,
3. Impact landowners (if any),
4. OCP Management Teams,
5. OCP Public Response Personnel (as listed in Section 5 of this document).

Within 24 hours, following contact with the public response personnel, incidents will be reported to the Region 5 office staff assigned to the project.

Based on the appropriate level of emergency response and the magnitude of the event, a crisis event center will be established. For minor emergencies, this will be held on Cardinal property. For major or serious emergencies, a crisis event center will be established at a safe location. This will serve as the headquarters for communication on the emergency. OPC will establish a liaison to communicate with the public and impacted landowners.

This liason will then communicate to the public and impacted landowners about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

OPC will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), OPC will provide periodic updates on the progress of the response action(s).

OPC will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO<sub>2</sub> source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team). A detailed list of these people will be developed and updated periodically.

## **7 Plan Review**

In accordance with 40 CFR 146.94(d), this ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency,
- Within one (1) year of an area of review (AOR) reevaluation,
- Within a time to be determined as part of the permit following any significant changes to the injection process or the injection facility, or an emergency event, or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, OCP will provide the permitting agency with documentation supporting the “no amendment necessary” determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within six months following an event that initiates the ERRP review procedure.

## **8 Staff Training and Exercise Procedures**

OCP will develop a Standard Operating Procedure (SOP) in tandem with the contractors that provide the surface capture and compression equipment, the surface monitoring system, and among other contractors that detail the operational procedures to be followed in the event of an emergency.

Included in this SOP will be specific details that can be used to train the project operators regarding the ERRP. Based on these SOPs, annual training and testing will be provided to all those involved with the project as well as those identified in Section 5 of this document.

All personnel identified and assigned as responding personnel in the document will complete initial training prior to the commencement of operations. Documentation of this initial training as well as annual certifications will be documented and retained.

## 9 References

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**Class VI Injection Well: Quality Assurance and Surveillance Plan**

Version 1.0  
June 20, 2022

Prepared by:

**One Carbon Partnership, LP**

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## **List of Acronyms**

ACZ	Above Confining Zone
ACZ1	Proposed Above Confining Zone Well
CBL	Cement Bond Log
CCS	Carbon Capture and Sequestration
CCS1	Proposed Injection Well
CO <sub>2</sub>	Carbon Dioxide
EPA	Environmental Protection Agency
MIT	Mechanical Integrity Testing
NA	Not Applicable
OBS1	Deep Observation Well
OCF	One Carbon Partnership, LP
PISC	Post Injection Site Care and Site Closure
PNL	Pulsed Neutron Logging
QA	Quality Assurance
QASP	Quality Assurance Surveillance Plan
QC	Quality Control
SCADA	Supervisory Control and Data Acquisition
SOP	Standard Operating Procedure
TBD	To Be Determined
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
USDW1	Proposed Lowermost USDW Monitor Well

## 1 Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at One Carbon Partnership, LP's (OCP) facility in Union City, IN for the Hoosier #1 Project. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

---

Signature

[INSERT TYPED NAME]

[INSERT TITLE]

---

Date

---

Signature

[INSERT TYPED NAME]

[INSERT TITLE]

---

Date

---

Signature

[INSERT TYPED NAME]

[INSERT TITLE]

---

Date

## 2 Distribution List

The following project participants will receive the completed QASP and all future updates for the duration of the project. The Project Manager will be responsible to ensure that all people on the distribution list below receives the most current version of the approved QASP.

### One Carbon Partnerhsip, LP (OCP)

Jeremy Herlyn

Plant Manager, Cardinal Ethanol  
1554 N. 600 E.  
Union City, IN 47390  
XXX-XXX-XXXX

Scott Rennie

CEO, Vault 44.01  
1554 N. 600 E.  
Union City, IN 47390  
XXX-XXX-XXXX

Well Location: 1554 N. 600 E.  
Union City, IN 47390  
Randolph County  
CO<sub>2</sub> Injection Well Location for Cardinal CCS #1  
Latitude 40.186587°  
Longitude -84.864284°

### **3 Project Management**

#### **3.1 Project/Task Organization**

##### **3.1.1 Key Individuals and Responsibilities**

The project includes participation from partners in OCP, Cardinal Ethanol and Vault 44.01. Testing and monitoring responsibilities will be shared between these two partners with support from various subcontractors. Seven subcategories have been identified for the testing and monitoring program with varying responsibilities assigned.

1. Shallow Groundwater Sampling and Monitoring,
2. Deep Groundwater Sampling and Monitoring,
3. Injection Well Monitoring,
4. Mechanical Integrity Testing (MIT),
5. Pressure and Temperature Monitoring,
6. Carbon dioxide (CO<sub>2</sub>) Stream Analysis,
7. Plume Modeling.

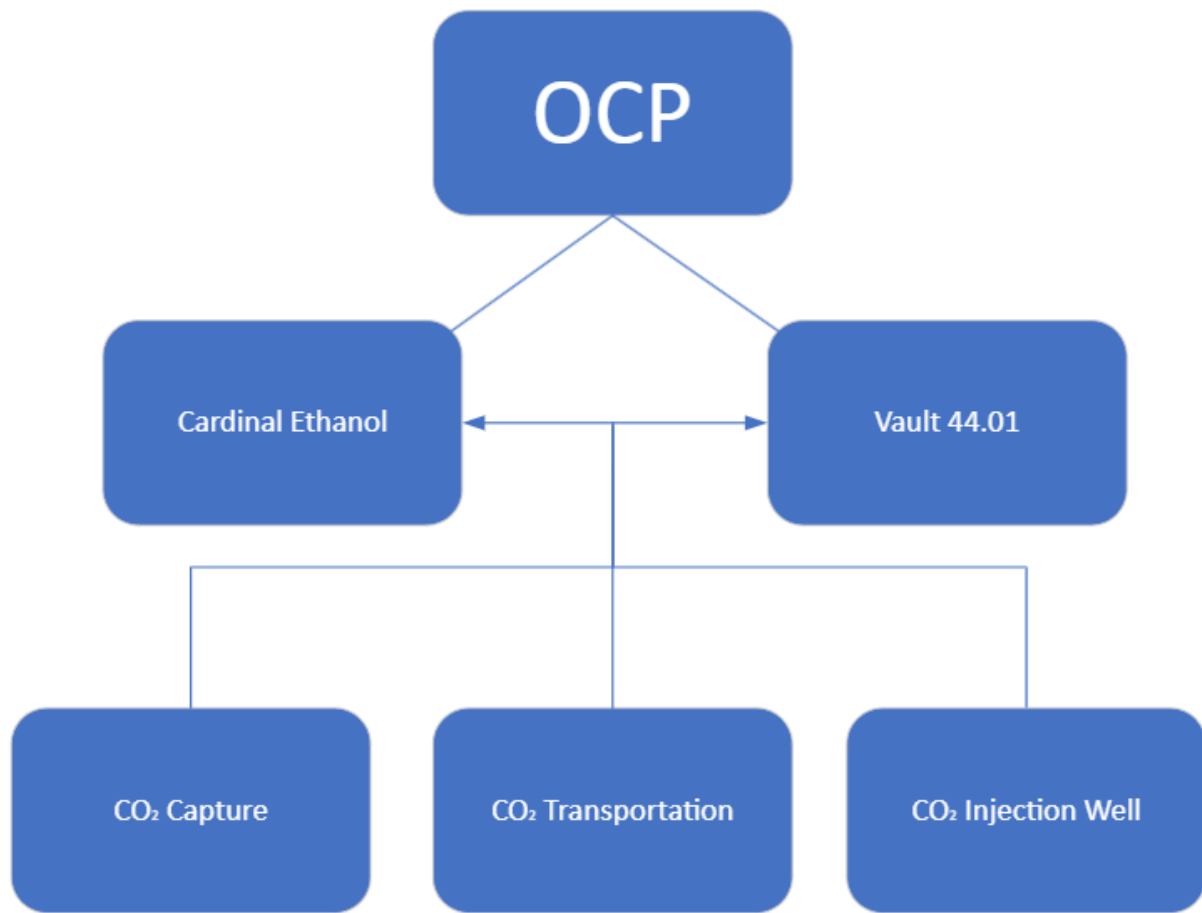
##### **3.1.2 Independence from Project Quality Assurance Manager and Data Gathering**

The physical samples to be collected, and the data gathered as a part of the monitoring program will be, on occasion, analyzed, processed, and/or witnessed by third party contractors, independent of the laid out project management structure.

##### **3.1.3 Project Quality Assurance Plan Responsibility**

OCP will be responsible for maintaining and distributing the official, approved Project QASP. Vault will review the QASP periodically and discuss with the Environmental Protection Agency (EPA) should changes to the plan be warranted.

### 3.1.4 Organizational Chart for Project Organizational Structure



**Figure 1. Organizational Chart for Key Project Personnel and Responsibilities**

## 3.2 A.2. Problem Definition/Background

### 3.2.1 A.2.a. Reasoning

The OCP carbon capture and sequestration (CCS) project has a robust monitoring program, which includes operational, plume, and environmental components.

Operational monitoring serves to ensure that all procedures and processes associated with the project are safe. Data will be collected to monitor the response of the sequestration unit and layers overlying the confining zone by monitoring the following parameters:

- Injection pressure,
- Injection Well Annulus pressure,
- Mt. Simon pressure,
- Above Confining Zone (ACZ) formation pressure,
- Lowermost Underground Source of Drinking Water (USDW) pressure.

In addition to the pressure components of the operational monitoring, additional parameters such as injection rate, total volume/mass injected, injection well temperature profile, and passive seismic data will be collected and evaluated.

The plume monitoring component of the program will provide information to evaluate the extent to which the CO<sub>2</sub> plume has spread and whether any leakage of the CO<sub>2</sub> through the caprock has occurred. The primary component of this monitoring is Pulsed Neutron Logging (PNL), but additional data will be gathered from pressure and temperature monitoring.

The environmental component of the monitoring program is meant to determine if CO<sub>2</sub> is being released into the shallow groundwater layers or the environment. The primary component of this monitoring consists of fluid sampling and monitoring, with additional monitoring from the PNL, which is the primary component of the plume monitoring program.

The robust monitoring program developed from this project is based on experience gained from other approved Class VI projects, as well as extensive geologic evaluation, reservoir modeling, and understanding of federal regulations on the matter. The result of this experience yields a high level of confidence that the Mt. Simon is a suitable injection formation, and that the Eau Claire is a sufficient caprock, capable of ensuring the injected CO<sub>2</sub> will remain permanently in the Mt. Simon.

The primary goal of the monitoring program is to continue to demonstrate the activities of this project are safe for the health of the general public and environment. In order to help facilitate this demonstration, the QASP was developed to ensure the quality of the demonstration methods meet the requirements of the EPA Underground Injection Control (UIC) Program for Class VI wells.

### 3.2.2 A.2.b. Reasons for Initiating the Project

The purpose of the Vault-Cardinal CCS project is to demonstrate the ability of the Mt. Simon Sandstone to accept and retain supercritical CO<sub>2</sub> in eastern Indiana. This sequestration targets the reduction of CO<sub>2</sub> emissions from the ethanol facility into the atmosphere. In order to demonstrate the efficacy of this project and the long term sequestration of CO<sub>2</sub>, the rigorous testing and monitoring program presented in this application will be implemented. The QASP presented in this document provides additional information on the methodology and technical standards that will comprise the proposed testing and monitoring program.

### 3.2.3 A.2.c. Regulatory Information, Applicable Criteria, Action Limits

Class VI regulations stipulate that the owners or operators of Class VI wells perform several types of activities throughout the life of the project to ensure the following:

- i. That the wells maintain their mechanical integrity,

- ii. That injected fluid migration and pressure changes are within the limits described in the permit application, and
- iii. That USDWs are not endangered during or after operations.

The activities to demonstrate the objectives detailed above consist of, but are not limited to, the following:

- MIT,
- Well tests performed on the injection well during operation,
- Groundwater monitoring from several zones,
- CO<sub>2</sub> and pressure plume tracking.

This document is intended to detail the methods of measurement and the steps that will be taken to ensure the quality of the collected data so that confident informed decisions can be made during the project.

### **3.3 A.3. Project/Task Description**

#### **3.3.1 A.3.a/b. Summary of Work to be Performed**

Table 1 displays the major tasks for the testing and monitoring program described in Testing and Monitoring Section of this permit application. This table displays the location of monitoring points, method of sampling, analytical technique applied, lab/custody procedures to be followed (if applicable), and the purpose of each item. Details on the frequency of the testing and monitoring program activities can be found in the Testing and Monitoring Plan and Pre-operation Testing sections.

Tables 2 and 3 display details of the instrumentation used at each monitoring location, and geophysical surveys, respectively.

**Table 1. Summary of Testing and Monitoring**

<b>Activity</b>	<b>Location(s)</b>	<b>Method</b>	<b>Analytical Technique</b>	<b>Lab/Custody</b>	<b>Purpose</b>
<b>CO<sub>2</sub> stream analysis</b>					
CO <sub>2</sub> stream analysis – downstream	CO <sub>2</sub> Delivery Pipeline	Direct Sampling	Chemical Analysis	to be determined (TBD)	Monitor injectate quality and composition
<b>Continuous Recording</b>					
Injection rate	CCS1 Wellhead	Flowmeter	Direct Measure	Not Applicable (NA)	Monitoring injection rate
Injection volume	CCS1 Wellhead	Flowmeter	Direct Measure	NA	Calculated injection volume
Injection pressure	CCS1 Wellhead	Continuous Monitoring	Direct Measure	NA	Monitoring injection pressure
Wellhead pressure	ACZ Wellhead	Continuous Monitoring	Direct Measure	NA	
Annular pressure	CCS1 Wellhead Deep Observation Well (OBS1) Wellhead	Continuous Monitoring	Direct Measure	NA	Monitoring annulus pressure
Downhole pressure	CCS1 Injection Interval OBS1 Injection Interval	Downhole Gauge	Direct Measure	NA	Monitoring injection zone
Downhole temperature	CCS1 Wellbore	Downhole Gauge	Direct Measure	NA	Monitoring injection zone, wellbore integrity
Microseismic	Various Monitoring Stations	Geophones and Seismometers	Direct Measure	NA	Injection zone and confining zone integrity

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
<b>Well Integrity</b>					
Corrosion monitoring	CO <sub>2</sub> Delivery Pipeline CCS1 Wellhead	Coupon	Direct Measure Chemical Analysis	TBD	Monitoring injectate, wellbore integrity
Annular fluid volume	CCS1 Wellhead OBS1 Wellhead	Site Glass Readings	Direct Measure	NA	Monitoring annulus fluid volume changes
Mechanical integrity (internal)	CCS1 Wellhead OBS1 Wellhead	Annulus Pressure Test	40 CFR 146.89 (b)	NA	Wellbore integrity
Mechanical integrity (external)	CCS1 Wellbore OBS1 Wellbore (temp log only)	Various	40 CFR 146.87 (a)(4) 40 CFR 146.89 (c)(2) Log Interpretation	NA	Wellbore integrity
Cement Evaluation	CCS1 Wellbore OBS1 Wellbore ACZ1 Wellbore	Logging	Direct Measure Log Interpretation	NA	Wellbore integrity
<b>Plume Tracking</b>					
PNL	CCS1 Wellbore OBS1 Wellbore	Logging	Direct Measure Log Interpretation	NA	CO <sub>2</sub> saturation, vertical plume development
Downhole pressure	OBS1 Injection Interval CCS1 Injection Interval	Direct Sampling	Direct Measure	NA	Monitoring injection zone pressure, plume monitoring, confining zone integrity
Microseismic Monitoring	Minimum of 5 stations TBD	Geophones and Seismometers	Direct Measure	NA	Injection zone and confining zone integrity

<b>Activity</b>	<b>Location(s)</b>	<b>Method</b>	<b>Analytical Technique</b>	<b>Lab/Custody</b>	<b>Purpose</b>
Time-lapse 3D Seismic Data	Area sufficient to image an 8.97 mi <sup>2</sup> plume	3D Seismic Surface Seismic Survey	Data Analysis and Interpretation	NA	Indirect measurement of plume development
<b>Fluid Sampling</b>					
Shallow Groundwater Sampling (Glacial Drift)	12 wells spatially distributed throughout the AoR	In-situ	Chemical Analysis	Table 4 for parameters	Detection of changes in groundwater quality for the shallow USDWs.
Lowermost USDW Sampling (Maquoketa Shale)	USDW1	In-situ	Chemical Analysis	Table 5 for parameters	Detection of changes in the groundwater quality in the lowermost USDW.
Above Confining Zone Sampling (Knox Formation)	ACZ1	In-situ	Chemical Analysis	Table 6 for parameters	Detection of changes in groundwater quality above the confining zone.
Injection Interval Monitoring (Mt. Simon)	OBS1	In-situ	Chemical Analysis	Table 7 for parameters	Detection of changes in groundwater quality, geochemistry, and CO <sub>2</sub> saturation in the injection interval.

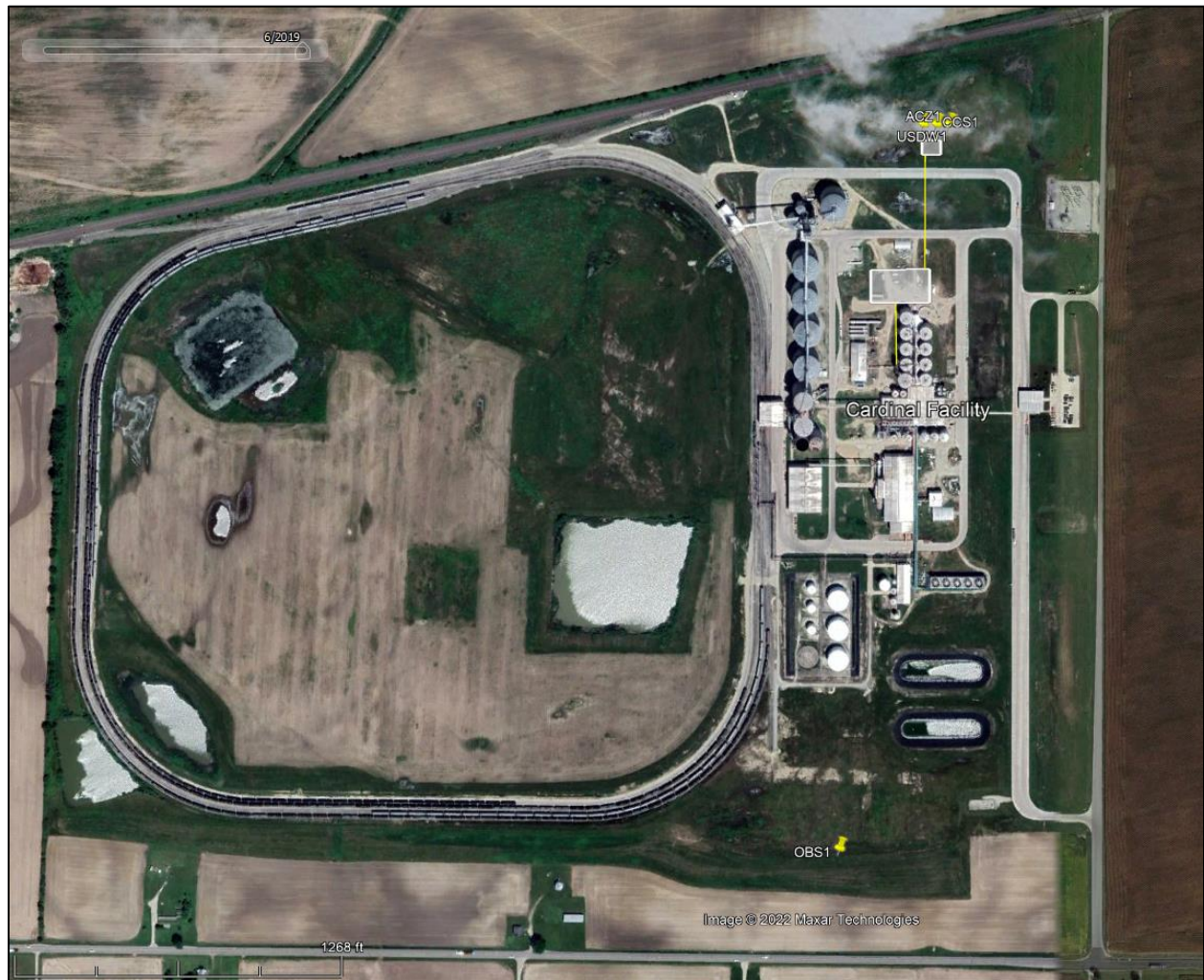
**Table 2. Instrumentation Summary**

<b>Monitoring Location</b>	<b>Instrument Type</b>	<b>Monitoring Target/Interval</b>	<b>Data Collection Location(s)</b>	<b>Explanation</b>
CO <sub>2</sub> Facility	Gas sampling port	Surface	Downstream of Compressor	Monitoring injectate quality and composition
CCS1	Temperature Pressure Flow	Wellhead - injection Wellhead - injection Surface	Tubing Tubing Flowline	Monitoring operational parameters of surface and well equipment.
	Temperature Pressure	Wellbore - injection Wellbore - injection	Packer Packer	Monitoring operational parameters at bottom hole conditions.
	Pressure	Wellhead - annulus Wellhead - MIT (internal)	Annulus Annulus	Monitoring well integrity.
	Corrosion	Surface	Upstream from Wellhead	Monitoring corrosion of the wellhead equipment and tubulars before potential future equipment failure.
OBS1	Pressure	Wellbore – injection zone	Packer	Monitoring bottomhole injection pressure in injection zone
	Pressure	Wellhead - annulus Wellhead - MIT (internal)	Annulus Annulus	Monitoring well integrity.
ACZ1	Pressure	Wellhead - ACZ zone	Surface	
Seismic Stations	Seismometer(s) Geophones	Surface and borehole	All Strata Various Locations TBD	Passive seismic monitoring equipment to be used to monitor and detect seismic events over within the AoR.

**Table 3. Geophysical Surveying Summary**

<b>Survey Activity</b>	<b>Well</b>	<b>Tool/Survey Description</b>	<b>Explanation</b>
Logging	CCS1	Temperature/Radioactive Tracer Log	Mechanical Integrity, Fluid Movement, CO <sub>2</sub> Detection
		Pressure Falloff Test	Injection Zone Pressure Response, Geophysical and Geomechanical Monitoring
		Preoperation Testing Logging	Well charecterization
		PNL	Mechanical Integrity, Fluid Movement, CO <sub>2</sub> Detection
	OBS1	Temperature Log	Mechanical Integrity, Fluid Movement, CO <sub>2</sub> Detection
		Preoperation Testing Logging	Well charecterization
		PNL	Mechanical Integrity, Fluid Movement, CO <sub>2</sub> Detection
	ACZ1	Cement Bond Log (CBL)	Mechanical Integrity
Seismic Stations	Surface Survey Area	3D Seismic Survey	Monitor extent of CO <sub>2</sub> plume.

### 3.3.2 A.3.c. Geographic Locations



**Figure 2. Cardinal Ethanol Facility and Associated CCS Related Equipment**



**Figure 3. Ethanol Facility, Flowlines, Surface Capture Facility, CCS1, Proposed Lowermost USDW Monitor Well**

**(USDW1), and Proposed Lowermost USDW Monitor Well (ACZ1) Location**



**Figure 4. Ethanol Facility and OBS1 Location**

**3.3.3 A.3.d. Resource and Time Constraints**

No major time or resource constraints have been identified for the Hoosier project. Wells drilled, tested, and monitored as laid out in the permit application will serve their purpose for pre-operation, active operations, and post closure care.

Following the full closure of the project and the post operational monitoring period OCP plans to plug and abandon all wells associated with the project in a manner consistent with federal regulations. As part of the financial assurance package, money will be allocated to ensure these activities are fully funded.

### 3.4 A.4.Quality Objectives and Criteria

#### 3.4.1 A.4.a. Performance/Measurement Criteria

The objective of the QA system for the monitoring program is to develop and utilize procedures for surface and subsurface monitoring, field samples, laboratory analysis, and routine reporting. The results of these activities will demonstrate the viability, characterization, and non-endangerment objectives of the project.

Groundwater monitoring will be conducted:

- Before injection begins,
- During injection operations,
- Post-injection operations.

Specific monitoring frequency and timing is provided in the preoperational testing plan, the testing and monitoring plan, and the post-injection site care portions of the application. This monitoring will be performed on shallow and deep groundwater wells. Analytical and monitoring parameters for groundwater samples are provided in Tables 4-7.

*Note for Tables 4-7:*

*ICP – inductively coupled plasma*

*MS – mass spectrometry*

*OES – optical emission spectrometry*

*GC-P – gas chromatography – pyrolysis*

Table 8 contains analytes for CO<sub>2</sub> stream analysis.

Tables 9 and 10 shows other CO<sub>2</sub> and injection related parameters, instrumentation, and standards of analysis.

Table 11 contains detail on the major monitoring outputs.

The list of analytes provided herein may be reassessed periodically and adjusted as necessary based on the effectiveness of the current testing and monitoring program with respect to its objectives.

Key monitoring areas and their major methods and analytes include (but are not limited to):

- i. Shallow Groundwater Sampling
  - a. Aqueous chemical concentrations (Table 4)
- ii. Deep Groundwater Sampling
  - a. Aqueous chemical concentrations (Table 5-7)
- iii. Well Logging
  - a. PNL
- iv. MIT and Corrosion Monitoring
  - a. PNL (external)
  - b. Temperature (external)
  - c. Annulus Pressure Test (internal)
  - d. CBL (external)
  - e. Coupon monitoring
- v. Pressure and Temperature Monitoring
  - a. In-situ pressure/temperature gauges
  - b. Baseline data

- c. Surface pressure/temperature gauges
- vi. CO<sub>2</sub> Stream Analysis
  - a. CO<sub>2</sub> Purity
  - b. Total Hydrocarbons as Methan
  - c. Carbon Monoxide
  - d. Oxides of Nitrogen
  - e. Nitrogen
  - f. Oxygen
  - g. Methane
  - h. Hydrogen Sulfide
  - i. Sulphur Dioxide
  - j. Acetaldehyde
  - k. Ethanol
- vii. Geophysical Monitoring
  - a. 3D seismic profile
  - b. Time-lapse reporting
  - c. Seismic activity monitoring

**Table 4. Summary of Analytical and Field Parameters for Fluid Samples from Shallow Groundwater (GW2-13) Samples**  
(All analysis to be performed by Cardinal or a designed third party laboratory to be identified.)

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	Quality Control Requirements
<u>Cations:</u> Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020	0.001 to 0.1 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B	0.005 to 0.5 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
<u>Anions:</u> Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0	0.02 to 0.13 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, and duplicated at 10% or greater frequency.
<u>Dissolved CO<sub>2</sub></u>	Coulometric Titration ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
<u>Total Dissolved Solids</u>	Gravimetry APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
<u>Alkalinity</u>	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
<u>pH (field)</u>	EPA 150.1	2 to 12 pH units	±0.2 pH units	Calibration per manufacturer specifications
<u>Specific conductance (field)</u>	APHA 2510	0 to 200 mS/cm	±1% of reading	Calibration per manufacturer specifications
<u>Temperature (field)</u>	Thermocouple	-5 to 50°C	±0.2°C	Calibration per manufacturer specifications

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director. Note 2: Analyte, dilution, and matrix dependent

**Table 5. Summary of Analytical and Field Parameters for Fluid Samples from Lowermost USDW Groundwater (USDW1) Samples.**  
(All analysis to be performed by Cardinal or a designed third party laboratory to be identified.)

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>Cations:</u> Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020	0.001 to 0.1 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B	0.005 to 0.5 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
<u>Anions:</u> Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0	0.02 to 0.13 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, and duplicated at 10% or greater frequency.
<u>Dissolved CO<sub>2</sub></u>	Coulometric Titration ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
<u>Isotopes:</u> δ <sup>13</sup> C of DIC	Isotope ratio mass spectrometry <sup>(3)</sup>	12.2 mg/L HCO <sub>3</sub> <sup>-</sup> for δ <sup>13</sup> C	±0.15% for δ <sup>13</sup> C	10% duplicates; 4 standards/batch
<u>Total Dissolved Solids</u>	Gravimetry APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
<u>Water Density (field)</u>	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
<u>Alkalinity</u>	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>pH (field)</u>	EPA 150.1	2 to 12 pH units	±0.2 pH units	Calibration per manufacturer specifications
<u>Specific conductance (field)</u>	APHA 2510	0 to 200 mS/cm	±1% of reading	Calibration per manufacturer specifications
<u>Temperature (field)</u>	Thermocouple	-5 to 50°C	±0.2°C	Calibration per manufacturer specifications

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Note 2: Analyte, dilution, and matrix dependent

Note 3: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

**Table 6. Summary of Analytical and Field Parameters for Fluid Samples from ACZ1**  
**(Cation, anion, TDS, and alkalinity analyte measurements will be performed by a laboratory meeting the requirements outlined in the EPA Environmental Laboratory Accreditation program. All other analysis to be performed by Cardinal or a designed third party laboratory, to be identified.)**

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>Cations:</u> Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020	0.001 to 0.1 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B	0.005 to 0.5 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
<u>Anions:</u> Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0	0.02 to 0.13 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, and duplicated at 10% or greater frequency.

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>Dissolved CO<sub>2</sub></u>	Coulometric Titration ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
<u>Isotopes: δ<sup>13</sup>C of DIC</u>	Isotope ratio mass spectrometry <sup>(3)</sup>	12.2 mg/L HCO <sub>3</sub> <sup>-</sup> for δ <sup>13</sup> C	±0.15% for δ <sup>13</sup> C	10% duplicates; 4 standards/batch
<u>Total Dissolved Solids</u>	Gravimetry APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
<u>Water Density (field)</u>	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
<u>Alkalinity</u>	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
<u>pH (field)</u>	EPA 150.1	2 to 12 pH units	±0.2 pH units	Calibration per manufacturer specifications
<u>Specific conductance (field)</u>	APHA 2510	0 to 200 mS/cm	±1% of reading	Calibration per manufacturer specifications
<u>Temperature (field)</u>	Thermocouple	-5 to 50°C	±0.2°C	Calibration per manufacturer specifications

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Note 2: Analyte, dilution, and matrix dependent

Note 3: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

**Table 7. Summary of Analytical and Field Parameters for Fluid Samples from Mt. Simon Groundwater (OBS1) Samples.**  
**(All analysis to be performed by Cardinal or a designed third party laboratory to be identified.)**

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>Cations:</u> Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020	0.001 to 0.1 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B	0.005 to 0.5 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, duplicates, and matrix spikes at 10% or greater.
<u>Anions:</u> Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography EPA Method 300.0	0.02 to 0.13 mg/L <sup>(2)</sup>	±15%	Daily calibration, blanks, and duplicated at 10% or greater frequency.
<u>Dissolved CO<sub>2</sub></u>	Coulometric Titration ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
<u>Isotopes:</u> δ <sup>13</sup> C of DIC	Isotope ratio mass spectrometry <sup>(3)</sup>	12.2 mg/L HCO <sub>3</sub> <sup>-</sup> for δ <sup>13</sup> C	±0.15% for δ <sup>13</sup> C	10% duplicates; 4 standards/batch
<u>Total Dissolved Solids</u>	Gravimetry APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
<u>Water Density (field)</u>	Oscillating body method	0.0000 to 2.0000	±0.0002 g/mL	Duplicate measurements
<u>Alkalinity</u>	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>pH (field)</u>	EPA 150.1	2 to 12 pH units	±0.2 pH units	Calibration per manufacturer specifications
<u>Specific conductance (field)</u>	APHA 2510	0 to 200 mS/cm	±1% of reading	Calibration per manufacturer specifications
<u>Temperature (field)</u>	Thermocouple	-5 to 50°C	±0.2°C	Calibration per manufacturer specifications

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Note 2: Analyte, dilution, and matrix dependent

Note 3: Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

**Table 8. Summary of Analytical Parameters for CO<sub>2</sub> Stream.**

**All analysis to be performed by Cardinal or a designed third party laboratory, to be identified. Primary constituents to be reported are in bold.**

<b>Parameters</b>	<b>Analytical Methods<sup>(1)</sup></b>	<b>Detection Limit/Range</b>	<b>Typical Precisions</b>	<b>QC Requirements</b>
<b>CO<sub>2</sub> Purity</b>	ISBT 2.0	5 % v/v	±10 % of reading	Calibration per manufacturer specifications
<b>Total Hydrocarbons as Methane</b>	ISBT 10.0	0.1 ppm v/v as CH <sub>4</sub>	5-10% of reading	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Total Non-Methane Hydrocarbons (TNMHC)	ISBT 10.1	0.1 ppm v/v as CH <sub>4</sub>		
<b>Carbon Monoxide (CO)</b>	ISBT 5.0	0.5 ppm v/v	±20% of reading	Duplicate analysis
Ammonia (NH <sub>3</sub> )	ISBT 6.0	0.5 ppm v/v		
<b>Oxides of Nitrogen (NO<sub>x</sub>)</b>	ISBT 7.0	0.5 ppm v/v	±20% of reading	Duplicate analysis
Nitrogen Dioxide (NO <sub>2</sub> )	ISBT 7.1	0.5 ppm v/v		
Nitric Oxide (NO)	ISBT 7.2	0.5 ppm v/v		
<u>Source Specific Parameters:</u>				
Hydrogen Cyanide (HCN)	ISBT 17.0	0.5 ppm v/v		
Vinyl Chloride (C <sub>2</sub> H <sub>3</sub> Cl)	ISBT 18.0	0.1 ppm v/v		
Phosphine (PH <sub>3</sub> )	ISBT 19.0	0.1 ppm v/v		
Ethylene Oxide (C <sub>2</sub> H <sub>4</sub> O)	ISBT 20.0	0.1 ppm v/v		
<u>Non-Condensable Gases:</u>				
<b>Nitrogen (N<sub>2</sub>)</b>	ISBT 4.0	4.0 ppm v/v	±10% of reading	Daily standard within 10% of calibration, secondary standard after calibration
<b>Oxygen (O<sub>2</sub>)</b>	ISBT 4.0	4.0 ppm v/v	±10% of reading	
Argon (Ar)	ISBT 4.0	4.0 ppm v/v		

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
Hydrogen (H <sub>2</sub> )	ISBT 4.0	10.0 ppm v/v		
Helium (He)	ISBT 4.0	10.0 ppm v/v		
<u>Volatile Hydrocarbons:</u>				
<b>Methane</b>	ISBT 10.1	0.5 ppm v/v	5-10% of reading	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Ethylene	ISBT 10.1	0.5 ppm v/v		
Ethane	ISBT 10.1	0.5 ppm v/v		
Propylene	ISBT 10.1	0.5 ppm v/v		
<u>Volatile Hydrocarbons</u> <u>cont'd:</u>				
Propane	ISBT 10.1	0.5 ppm v/v		
Isobutane	ISBT 10.1	0.5 ppm v/v		
n-Butane	ISBT 10.1	0.5 ppm v/v		
Butenes	ISBT 10.1	0.5 ppm v/v		
Isopentane	ISBT 10.1	0.5 ppm v/v		
n-Pentane	ISBT 10.1	0.5 ppm v/v		
Pentenenes	ISBT 10.1	0.5 ppm v/v		
C <sub>6+</sub>	ISBT 10.1	0.5 ppm v/v		
<u>Aromatic Hydrocarbons:</u>				
Benzene (AHC)	ISBT 12.0	0.002 ppm v/v		
Toluene	ISBT 12.0	0.002 ppm v/v		
Ethyl Benzene	ISBT 12.0	0.002 ppm v/v		
m+p Xylene	ISBT 12.0	0.002 ppm v/v		
o-Xylene	ISBT 12.0	0.002 ppm v/v		

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
<u>Volatile Sulfur Compounds:</u>				
<b>Hydrogen Sulfide (H<sub>2</sub>S)</b>	ISBT 14.0	0.02 ppm v/v	5-10% of reading	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Carbonyl Sulfide (COS)	ISBT 14.0	0.02 ppm v/v		
<b>Sulphur Dioxide (SO<sub>2</sub>)</b>	ISBT 14.0	0.02 ppm v/v	5-10% of reading	
Methyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
Ethyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
Dimethyl Sulfide	ISBT 14.0	0.02 ppm v/v		
Carbon Disulfide	ISBT 14.0	0.02 ppm v/v		
i-Propyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
t-Butyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
n-Propyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
Methyl Ethyl Sulfide	ISBT 14.0	0.02 ppm v/v		
sec-Butyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
i-Butyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
Dimethyl Disulfide	ISBT 14.0	0.02 ppm v/v		
n-Butyl Mercaptan	ISBT 14.0	0.02 ppm v/v		
Dimethyl Disulfide	ISBT 14.0	0.02 ppm v/v		
Other Sulfurs	ISBT 14.0	0.02 ppm v/v		
Total Sulfur Content (TSC)	ISBT 13.0	0.02 ppm v/v		
<u>Volatile Oxygenates:</u>				
<b>Acetaldehyde (AA)</b>	ISBT 11.0	0.05 ppm v/v	5-10% of reading	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Ethyl Oxide	ISBT 20.0	0.1 ppm v/v		
Dimethyl Ether	ISBT 11.0	0.1 ppm v/v		

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
Methyl Ethyl Ether	ISBT 11.0	0.2 ppm v/v	5-10% of reading	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Methanol (MeOH)	ISBT 9.0	0.2 ppm v/v		
Propionaldehyde	ISBT 11.0	0.2 ppm v/v		
Acetone	ISBT 11.0	0.2 ppm v/v		
<b>Ethanol</b>	ISBT 11.0	0.2 ppm v/v		
Isopropanol	ISBT 11.0	0.2 ppm v/v		
Ethyl Acetate	ISBT 11.0	0.2 ppm v/v		
t-Butanol	ISBT 11.0	0.2 ppm v/v		
n-Propanol	ISBT 11.0	0.2 ppm v/v		
2-Butanol	ISBT 11.0	0.2 ppm v/v		
Isobutanol	ISBT 11.0	0.2 ppm v/v		
n-Butanol	ISBT 11.0	0.2 ppm v/v		
Isoamyl Alcohol	ISBT 11.0	0.2 ppm v/v		
Isoamyl Acetate	ISBT 11.0	0.2 ppm v/v		

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 9. Summary of Analytical Parameters for Corrosion Coupons.**

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2005	0.005 mg	±2%	Annual third party calibration of scale (certification number to be provided)
Thickness	NACE RP0775-2005	0.001 mm	±0.005	Factory calibration

**Table 10. Summary of Measurement Parameters for Field Gauges.\***

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Injection tubing temperature	ANSI Z540-1-1994	±0.001 °F, 0-500 °F	±0.01 °F	Annual third party calibration of scale (cert number to be provided)
Injection tubing pressure	ANSI Z540-1-1994	±0.001 psi, 0-3,000 psi	±0.01 psi	Annual third party calibration of scale (cert number to be provided)
Injection flow rate	NA	± 0.1% of rate	50,522-303-133 lb/hr	Annual third party calibration of scale (cert number to be provided)
CCS1 annulus pressure	ANSI Z540-1-1994	±0.001 psi, 0-3,000 psi	±0.01 psi	Annual third party calibration of scale (cert number to be provided)
CCS1 downhole pressure	ANSI Z540-1-1994	±0.001 psi, 0-10,000 psi	±0.01 psi	Annual third party calibration of scale (cert number to be provided)
CCS1 downhole temperature	ANSI Z540-1-1994	±0.001 °F, 0-300 °F	±0.01 °F	Annual third party calibration of scale (cert number to be provided)
OBS1 annulus pressure	ANSI Z540-1-1994	±0.001 psi, 0-3,000 psi	±0.01 psi	Annual third party calibration of scale (cert number to be provided)
OBS1 downhole pressure	ANSI Z540-1-1994	±0.001 psi, 0-10,000 psi	±0.01 psi	Annual third party calibration of scale (cert number to be provided)
ACZ1 wellhead pressure	ANSI Z540-1-1994	±0.001 psi, 0-3,000 psi	±0.01 psi	Annual third party calibration of scale (cert number to be provided)

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

\*Standards, detection limits/ranges, and precision parameters are subject to change based on the finalization of equipment

**Table 11. Actionable Testing and Monitoring Outputs.**

<b>Activity or Parameter</b>	<b>Project Action Limit</b>	<b>Detection Limit</b>	<b>Anticipated Reading</b>
Part II (External) MIT <i>PNL</i>	Action to be taken if CO <sub>2</sub> is outside of anticipated range or location.	TBD based on contractor tool specifications	TBD based on results of baseline logs Readings vary by zone.
Part II (External) MIT <i>Temperature Logging</i> <i>RAT Logging</i>	Action to be taken if an anomaly in the temperature/GR profile is identified.	TBD based on contractor tool specifications	TBD based on results of baseline logs Readings vary by zone.
Part I (Internal) MIT <i>Annulus Pressure Test</i>	Action to be taken if pressure change is greater than 3% in one hour.	See Table 10	Less than 3% pressure change in one hour.
Surface pressure (CCS1)	Action to taken if injection pressure is above MAIP.	See Table 10	Less than the MAIP as detailed in Section 6
Downhole pressure/temperature (CCS1)	Action to taken if pressure is above maximum allowable botthom hole pressure (MABHP).	See Table 10	Less than the corresponding BHP as determined in the MAIP in Section 6
Downhole pressure (OBS1)	Action to be taken if pressure varies significantly from modeled values or is above MABHP.	See Table 10	TBD based on results of a baseline pressure and temperature survey
Water quality	Action to be taken if ACZ or USDW/GW water quality deviates significantly from baseline water quality measurements.	See Tables 4-7	TBD based on baseline samples to be taken prior to injection.
3D seismic profiling	Action to be taken if CO <sub>2</sub> plume is detected outside of modeled plume/AoR.	Variable dependent on fluid saturation, formation velocities, etc.	Similar CO <sub>2</sub> plume migration in comparison to the model.
Passive seismic monitoring	Action to be taken if notable seismic activity is measured concurrent with injection operations.	Refer to ERRP section for further discussion on detection limits and action items.	Consistent with baseline/background seismic measurements.

### 3.4.2 A.4.b. Precision

For groundwater sampling, data accuracy will be assessed regularly by the collection and analysis of blanks to test procedures and matrix spikes to test lab and sampling procedures. Field blanks will be taken no less than one per sampling event to spot check for sample container contamination. Laboratory assessment of the precision of the analytes will be the responsibility of the laboratory chosen to analyze the field samples based on acceptable operating procedures.

Table 12 presents the specifications and precision information for the downhole pressure and temperature gauges to be used for downhole pressure and temperature monitoring in the injection and above confining zone intervals.

Table 13 presents the parameters and specifications for the logging tools to be used as part of the preoperational testing, testing and monitoring, and post injection site care programs.

### 3.4.3 A.4.c. Bias

Assessments of the analytical biases present in analysis are the responsibility of the contacted laboratories based on acceptable operating procedures. It is assumed there are no measurement biases for direct temperature, pressure, or logging measurements.

### 3.4.4 A.4.d. Representativeness

For groundwater sampling, data representativeness expresses the degree to which data accurately and precisely represents a characteristic of a sample population, parameter variations at a specific sampling point, a process condition, or an environmental condition. The sampling network laid out in the monitoring program is designed to provide data that is representative of site conditions.

For analytical results of individual groundwater samples, representativeness will be estimated by ion and mass balance determination. Ion balance determinations with  $\pm 10$  percent error, or less, will be considered valid. Mass balance determinations will be used in cases where the ion balance is great that the  $\pm 10$  percent threshold to attempt to determine the source of the measurement error.

For samples (and their duplicates) if the relative percent difference varies by more than 10%, the sample may be considered not representative.

### 3.4.5 A.4.e. Completeness

Data completeness is a measure of the amount of valid data obtained from a measurement point compared to the amount of data that was expected to be obtained from the data point under normal conditions. It is anticipated that 90 percent data completeness for groundwater samples will be considered acceptable to meet monitoring objectives.

For direct pressure, temperature, and logging measurements, it is anticipated that data will be recorded no less than 90 percent of the time.

### 3.4.6 A.4.f. Comparability

Data comparability expresses the confidence with which one data set can be compared to others. The data sets generated by this project are anticipated to be comparable to future data sets because of the use of standard methods of measurement and the high levels of QA/QC of data.

Historical groundwater quality data will be assessed for their level of quality, and assuming they are of high enough quality, will be used for comparative purposes. Direct pressure, temperature and logging measurements will be directly comparable to previously collected data.

### 3.4.7 A.4.g. Method Sensitivity

Tables 12 through 22 provide additional information on gauge and sensor sensitivities as well as logging and downhole tool specifications.

**Table 12. Pressure and Temperature (OBS1/ACZ1/CCS1) – Downhole Gauge Specifications.<sup>(1)</sup>**

Parameter	Value
Calibrated working pressure range	14.7 to 10,000 psi
Initial pressure accuracy	± 0.015% over full scale
Pressure resolution	0.006 psi/second
Pressure drift stability	0.01% Full Scale/Year
Calibrated working temperature range	to 150°C
Initial temperature accuracy	±0.1 °C
Temperature resolution	0.005 °C/second
Temperature drift stability	0.1% °C/yearr
Max temperature	150 °C
Instrument calibration frequency	From manufacturer

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 13. Representative Logging Tool Specifications.<sup>(1)</sup>**

Parameter	PNL	CBL	USIT	Temperature Log
Logging speed	1,000 ft/hr	1,800 ft/hr	2,700 ft/hr	900 ft/hr
Investigation	Formation	Formation, casing, cement bond quality	Formation, casing, cement bond quality	Formation
Temperature rating	Up to 350°F	Up to 302 °F	Up to 350°F	Up to 150°C
Pressure rating	Up to 15,000 psi	Up to 14,000 psi	Up to 20,000 psi	Up to 14,500 psi

Note 1: A suitable replacement tool could be used pending tool availability, updated specifications will be provided should such a change occur.

**Table 14. Temperature Field Probe – Post Compressor. <sup>(1)</sup>**

<b>Parameter</b>	<b>Value</b>
Calibrated working temperature range	0-500 °F
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 °F

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 15. Pressure Field Probe – Post Compressor. <sup>(1)</sup>**

<b>Parameter</b>	<b>Value</b>
Calibrated working pressure range	0-3,000 psi
Initial pressure accuracy	0.025%
Pressure resolution	0.001 psi

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 16. Flow Rate Field Flowmeter – Post Compressor. <sup>(1)</sup>**

<b>Parameter</b>	<b>Value</b>
Calibrated working flow rate range	50,000-303,000 lb/hr
Initial mass flow rate accuracy	<0.18%
Mass flow rate resolution	0.0001lb/hr

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 17. Temperature Field Probe – Injection Tubing. <sup>(1)</sup>**

<b>Parameter</b>	<b>Value</b>
Calibrated working temperature range	0-500 °F
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 °F

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 18. Pressure Field Probe – Injection Tubing.**<sup>(1)</sup>

<b>Parameter</b>	<b>Value</b>
Calibrated working pressure range	0-3,000 psi
Initial pressure accuracy	0.025%
Pressure resolution	0.001 psi

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 19. Flow Rate Field Flowmeter – Injection Tubing.**<sup>(1)</sup>

<b>Parameter</b>	<b>Value</b>
Calibrated working flow rate range	50,000-303,000 lb/hr
Initial mass flow rate accuracy	<0.18%
Mass flow rate resolution	0.0001lb/hr

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 20. Pressure Field Probe – CCS1 Annulus.**<sup>(1)</sup>

<b>Parameter</b>	<b>Value</b>
Calibrated working pressure range	0-3,000 psi
Initial pressure accuracy	0.025%
Pressure resolution	0.001 psi

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 21. Pressure Field Probe – OBS1 Annulus.**<sup>(1)</sup>

<b>Parameter</b>	<b>Value</b>
Calibrated working pressure range	0-3,000 psi
Initial pressure accuracy	0.025%
Pressure resolution	0.001 psi

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

### **3.5 A.5. Special Training/Certifications**

#### **3.5.1 A.5.a. Specialized Training and Certifications**

Geophysical surveying equipment and wireline logging tools will be operated by trained, qualified, and certified personnel. This will be verified by the respective contracted service company that provides the equipment and services. The data collected as a result of these activities will be analyzed according to industry standards.

There are currently no special certifications required for personnel to collect groundwater samples. These activities will still be performed by qualified personnel. Groundwater sampling will be performed by personnel trained to understand and follow the specific and detailed sampling procedures.

If requested OCP will provide the EPA with all laboratory Standard Operating Procedures (SOPs) for the specific parameters for the approved methods. Each laboratory technician conducting analysis on the samples will be trained in these SOPs for the standard method they are using. Technician certifications will be provided with the regular reports.

#### **3.5.2 A.5.b/c. Training Provider and Responsibility**

Training will be provided by the contracted operator or subcontractor responsible the collection of data.

### **3.6 A.6. Documentation and Records**

#### **3.6.1 A.6.a. Report Format and Package Information**

A report from OCP to EPA will contain all required project data, sampling results, and analytical analysis results. The frequency of this report is defined the Testing and Monitoring section of this application. Data will be provided in digital formats unless otherwise requested.

#### **3.6.2 A.6.b. Other Project Documents, Records, and Electronic Files**

Other files (i.e., well logs, reports, test results, etc.) will be provided as required by the UIC Program Director and Class VI Permit.

#### **3.6.3 A.6.c/d. Data Storage and Duration**

OCP will maintain digital copies of all relevant files for the project as stipulated in the Testing and Monitoring section of this application.

#### **3.6.4 A.6.e. QASP Distribution Responsibility**

OCP will be responsible for ensuring that all people listed on the distribution list below will receive the current copy of the approved QASP.

## 4 B. Data Generation and Acquisition

### 4.1 B.1. Sampling Process Design

Discussion in this section is focused on groundwater fluid sampling and does not discuss monitoring methods associated with non-physical samples (logging, seismic, pressure/temperature monitoring, etc.).

During the pre-operation and injection phases, groundwater sampling analysis is planned to include an extensive set of chemical analytes to aid in establishing a quality baseline data set. These analytes will include:

- i. primary and secondary EPA drinking water maximum contaminant levels,
- ii. are most responsive to CO<sub>2</sub> or brine contact,
- iii. are necessary for quality control (QC) and,
- iv. might be necessary for geochemical modeling.

The full set of monitoring parameters is provided in Tables 4-7. After a sufficient baseline dataset is established, the scope of the monitored analyte may shift to a more detailed subset of parameters that are:

- i. the most responsive to interaction with CO<sub>2</sub> or brine contact, and
- ii. are necessary for QC.

Implementation of a reduced set of parameters will be done in conjunction with consultation with the EPA.

Isotopic analyses will be performed on baseline samples to assist with verification of initial conditions, or to help with understanding non-project related variations. For non-baseline samples, isotopic analysis may be reduced in monitoring wells if review of historical analytical results or other data determines that is no longer needed. Isotopic analyses will be conducted using established and accepted methods.

During a period where a reduced set of analytes is used, should statistically significant trends develop that are presumed to be a result of unintended CO<sub>2</sub> or brine migration, the analytical list will be expanded to the initial, full set of analytical parameters.

ACZ groundwater samples will be analyzed using a laboratory that meets the requirements laid out in the EPA Environmental Laboratory Accreditation Program. All other samples will be analyzed by the operator or a contracted third party lab. Dissolved CO<sub>2</sub> will be analyzed by methods consistent with *Test Method B of ASTM D 513-06, "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water"* or a suitable equivalent.

#### 4.1.1 B.1.a. Design Strategy

##### 4.1.1.1 CO<sub>2</sub> Stream Monitoring Strategy

The primary purpose of analyzing the CO<sub>2</sub> stream is to evaluate the potential interactions of CO<sub>2</sub> and other potential constituents of the injected with formation solids. The analysis performed can also identify or potentially rule out interactions with well materials of construction. Establishing chemical composition of the injectate also will help to support the determination of whether this injectate meets the qualifications of hazardous waste paid out under the RCRA act from 1976. In addition to those stipulations laid out in the Resource Conservation and Recovery Act (RCRA act), this determination will also be made with respect to the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA act) from 1980.

Additional monitoring of chemical and physical characteristics of the CO<sub>2</sub> may help distinguish the injectate from native brine and gases if potential unintended leakage from the reservoir occurs. Injectate monitoring will occur at such frequency to detect potential changes to any physical or chemical properties that may result in deviation from the permit specifications and baseline data.

Yearly calibration of temperature, pressure, and flowrate probes and transponder meant to monitor the response of the injection of CO<sub>2</sub> into CCS1, will also be conducted annually at OBS1 and ACZ. Calibration reports will contain information on the test equipment used to calibrate the probes, including: equipment manufacturer information, serial numbers, calibration dates, and expiration dates of equipment and calibration.

#### *4.1.1.2 Corrosion Monitoring Strategy*

Corrosion coupon analysis will be conducted regularly to aid and ensuring the mechanical integrity of all equipment that comes in contact with the CO<sub>2</sub> stream. Coupons will be sent regularly to a third party company for analysis. This analysis will be conducted in accordance with NACE Standard RP-0775, or similar, to determine and document any potential corrosion or wear rates based on mass loss.

#### *4.1.1.3 Shallow Groundwater Monitoring Strategy*

Twelve dedicated monitoring wells have been selected for the shallow groundwater monitoring program. These wells will be drilled and installed to varying depths, from just below surface to above the lowermost USDW. These wells are intended to monitor and cover all currently used aquifers in the area. Further details on these wells are provided in the AoR section and the testing and monitoring section. These wells will be sampled routinely as is detailed in the Testing and Monitoring and Post Injection Site Care and Site Closure (PISC) section. The names of these wells are as follows:

- GW2
- GW3
- GW4
- GW5
- GW6
- GW7
- GW8
- GW9
- GW10
- GW11
- GW12
- GW13

Should alteration to these well names occur, proper updating of all relevant documentation and reports will be provided following these changes. These wells will be installed at various locations within and outside of the AoR. The wells will be spatially distributed as well as located at critical groundwater source points.

#### *4.1.1.4 Deep Groundwater Monitoring Strategy*

##### *USDWI*

One dedicated deep groundwater monitoring well will be installed in close proximity to the injection well (CCS1). This well will be installed and screened within the identified lowermost USDW. This well will serve as an early leakage detection point at or near the injection well. This interval is assumed to have sufficient permeability and porosity such that suitable fluid samples may be taken.

With the planned sampling methods and outlined frequency, it is expected that baseline conditions can be documented, and any natural variability in conditions can be characterized, and that unintended brine or CO<sub>2</sub> leakage will be detected quickly if it occurs.

##### *ACZI*

One dedicated above confining zone monitoring well (ACZ1) will also be installed in close proximity to the injection well. This well will be installed and completed within a permeable layer above the confining zone. This well will also serve as an early leakage detection point at or near the injection well. This well will be completed and a zone with sufficient permeability and porosity such that suitable fluid samples may be taken. This well will also be assumed to have sufficient permeability and porosity such that valid pressure monitoring may occur.

With the planned sampling methods and outline frequency, it is expected that baseline conditions can be documented, and any natural variability in the conditions can be characterized, and that unintended brine or CO<sub>2</sub> leakage will be detected quickly if it occurs. Sufficient data will be collected from this well to demonstrate that the effects of CO<sub>2</sub> injection are limited to the intended reservoir.

#### *OBS1 and CCS1*

Fluid samples will be collected from the injection well as part of the pre operational testing program. Once injection begins groundwater fluid sampling will occur in the Mt. Simon interval monitoring well (OBS1).

#### 4.1.2 B.1.b. Type and Number of Samples/Test Runs

Table 1 contains a listing of type in number of samples that will be run and collected from each of the wells mentioned above.

#### 4.1.3 B.1.c. Site/Sampling Locations

Groundwater sampling locations are provided above and table. Specific analytes for groundwater sampling are provided in Tables 4 through 7.

#### 4.1.4 B.1.d. Sampling Site Contingency

Locations of off-site sampling and monitoring points have not been finalized. It is currently anticipated, however, that no site access issues will be occur. All other wells will be located on the facility. If weather makes well access difficult, sampling schedules will be adjusted as necessary to ensure access and proper sampling may occur. Any changes to sampling schedule will be discussed with the EPA prior to them occurring.

CO<sub>2</sub> gas stream and corrosion coupon sampling points will also be located at the facility. If weather makes access to these sampling points difficult, sampling schedules will be adjusted as necessary to ensure access and proper sampling may occur. Any changes to sampling schedule will be discussed with the EPA prior to them occurring.

#### 4.1.5 B.1.e. Activity Schedule

Sampling frequencies and occurrences are detailed and the pre operational testing plan, the testing and monitoring plan, and the PISC plan sections of the permit application.

#### 4.1.6 B.1.f. Critical/Informational Data

Detailed documentation from field and laboratory activities will be taken during groundwater sampling and analytical work. Important documentation to be collected during these times are as follows:

- time and date of activity,
- person(s) performing activity,
- location of activity,
- equipment calibration data, and
- field parameter values.

during laboratory analysis much of the above listed critical data are generated during the analysis, and provided as part of the typical output reports from analysis. Additional noncritical data may be collected.

This data may include appearance and odor of sample, problems with well or any sampling equipment, and any weather conditions which may impact sampling.

#### 4.1.7 B.1.g. Sources of Variability

Potential sources of variability related to the aforementioned monitoring activities include:

- natural variation in fluid quality, formation pressure and temperature, and seismic activity,
- variation in fluid quality, formation pressure and temperature, and seismic activity due to injection operations,
- changes in aquifer recharge due to rainfall, drought, or snowfall,
- changes in instrument calibration during sampling or analytical activities,
- changes in collection staff or analytical staff,
- differences in environmental conditions during field sampling activities,
- changes in analytical data quality during the life of the project, and
- data entry errors related to maintaining a project database.

Activities that may serve to limit reduce or reconcile some of these sources of variability related to monitoring activities include:

- collecting long-term baseline data to observe and document natural variation in monitoring parameters,
- evaluating data in a timely manner after collection such that anomalies in the data can be observed and addressed and re sampling or reanalysis may occur,
- conducting statistical analysis of the data collected data to determine whether variability and data set is a result of project activities or natural variation (i.e., determining if variation is biased or statistically significant),
- maintaining a database of weather related data using on site and regional weather monitoring data or data collected from other near location sources,
- checking instrument calibration before during and after sampling or analysis,
- thoroughly training all staff to the standards that were detailed in sub sections 3.5.1 and 3.5.2,
- conducting routine quality assurance checks using third party reference materials and or blind and or duplicate sample checks, and
- developing a systematic review process of data that can include site and sample specific data quality checks.

## 4.2 B.2. Sampling Methods

Logging, geophysical monitoring, and pressure and temperature monitoring does not apply to this section and is, therefore, omitted.

### 4.2.1 B.2.a/b. Sampling SOPs

Groundwater samples will be collected primarily using a low-flow sampling method that is consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). This method intends for a flow through cell to be used should a flow through cell not be used. Field parameters will be measured and grab samples. All groundwater wells will be purged to ensure samples are representative of formation water quality.

Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities occur. Dedicated pumps will be installed in each of the monitoring wells to minimize potential cross contamination between wells.

Groundwater pH temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow through cell consistent with standard methods. Given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to the given equipment manufacturer procedures and using standard reference solutions.

When a flow through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in the following table.

**Table 22. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.**

Field Parameter	Stabilization Criteria
pH	± 0.2 units
Temperature	± 1 °C
Specific conductance	± 3% of reading in $\mu\text{S}/\text{cm}$
Dissolved oxygen	± 10% of reading or 0.3 mg/L, whichever is greater

After field parameters are stabilized per the above table, samples will be collected. Samples will be filtered through 0.45  $\mu\text{m}$  through filter cartridges as appropriate and consistent with ASTM D6564-00, or suitable alternative.

Prior to sample collection, filters will be purged with a minimum of 100 mL of well water or more for required by the filter manufacturer. For alkalinity and total  $\text{CO}_2$  sampling, reasonable effort will be made to minimize exposure to atmospheric conditions during filtration, collection in sample containers, and analysis.

For deep groundwater sampling, a wireline conveyed system with a sampling device capable of collecting downhole samples from discrete intervals will be utilized.

Deep groundwater monitoring wells will be developed extensively at the time of completion, with similar plans being followed in any other additional groundwater monitoring wells not laid out in the original application or within this document. Prior to sampling, any zones from these wells, these wells will be purged and ensure that stabilized criteria are met before taking representative samples.

Due to the planned large amount of fluid to be purged from these wells, there's the anticipation that at the time of sampling the fluid volume will be relatively small. Standard methods to develop these wells will be utilized such as down hole submersible pumps or swabbing.

For shallower groundwater monitoring wells, methods such as air lift or submersible pumps may be used to help with purging fluid from the wells.

#### 4.2.2 B.2.c. In-situ Monitoring

In-situ monitoring of groundwater chemistry and analytes is not currently planned.

#### 4.2.3 B.2.d. Continuous Monitoring

No continuous pressure monitoring is anticipated or planned at any of the shallow or deeper groundwater monitoring wells.

#### 4.2.4 B.2.e. Sample Homogenization, Composition, Filtration

Information on the sampling, homogenization, composition and filtration is provided in section 4.2.1.

#### 4.2.5 B.2.f. Sample Containers and Volumes

For CO<sub>2</sub> stream monitoring, samples will be collected and clean sample containers rated appropriately for sample collection pressure. To ensure a clean sample is taken, the collection cylinder(s) will be purged at least five times (with the sample gas) prior to sample collection.

Information for the regular CO<sub>2</sub> gas analysis is provided in Table 8.

For shallow and deep groundwater samples, all sample bottles will be new sample bottles and bags for analytes will be used as received from the vendor or contract analytical laboratory for the handle it if interest. A summary of sample containers used as presented in Table 25.

#### 4.2.6 B.2.g. Sample Preservation

For aqueous and groundwater samples, the preservation methods listed in Table 25 will be used.

At this time, preservation of CO<sub>2</sub> gas stream samples is not currently anticipated. In additional details of the sampling requirements are shown below in Table 24.

Corrosion coupon sampling only requires that the coupons be physically separated during transportation to prevent physical abrasion.

**Table 23. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO<sub>2</sub> Gas Stream Analysis.**

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO <sub>2</sub> gas stream	(1) 75 cm <sup>3</sup> mini gas cylinder (2) 2L MLB polybags	Sample storage cabinets	5 business days

#### 4.2.7 B.2.h. Cleaning/Decontamination of Sampling Equipment

As detailed in Section 4.2.1, dedicated pumps will be installed in each of the groundwater monitoring wells to minimize potential cross contamination between wells. These pumps will remain in each well throughout the project, except for routine maintenance. This includes pre-operational testing, testing which occurs during operation, and testing detailed in the PISC plan. Prior to pump installation, the pumps will be cleaned on the outside, with a non phosphate detergent. Pumps will be rinsed the minimum of three times with the ionized water. A minimum of 1 L of deionized water will then be pumped through the pump and sample tubing.

Once all pumps in their associated tubing are clean, they will be placed in plastic storage bags and transported for installation. All glassware to be used in the field will be cleaned first with tap water to

remove any loose dirt, then washed in a dilute nitric acid solution, and finally rinsed with deionized water before use.

Gas stream sampling containers will be disposed of or D contaminated by the analytical lab. No sampling equipment will be utilized with the corrosion coupons or annual field calibrations.

#### 4.2.8 B.2.i. Support Facilities

In order for proper groundwater sampling to occur, the following equipment are required:

- Air compressor
- Vacuum pump
- Generator
- Multi-electrode water quality measurement tool
- Analytical meters

It is assumed that the proper sampling tubes, connections and valves required to sample the gas stream will be supplied by the analytical lab, providing the sampling containers. Sampling will occur within the compression building.

Corrosion coupons will also be removed from the injection line within the compression building.

Field gauges will be removed from the wells. The deployment and retrieval of downhole well gauges will be done using procedures and equipment recommended by the vendor contract or per industry standard practice. It is currently anticipated that the primary way of deploying or retrieving these gauges is via wireline.

#### 4.2.9 B.2.j. Corrective Action, Personnel, and Documentation

Field staff are responsible for ensuring that all equipment is properly functioning. Corrective action will be performed on broken or malfunctioning equipment in the field as necessary. If corrective action cannot be taken in the field, the equipment will be uninstalled and returned to the manufacturer for repair or replacement. Any significant corrective actions that are required will be documented.

### 4.3 B.3. Sample Handling and Custody

Logging, geophysical monitoring, and pressure and temperature monitoring does not apply to this section and is, therefore, omitted.

Sample holding times provided in Table 25 will be consistent with those described By EPA guidelines from 1974, American Public Health Association in 2005, Wood in 1976, and ASTM Method D6517-00 from 2005.

After collection, all samples will be placed in an ice chest in the field and, which will be maintained thereafter to proximately 4 °C until analysis can be performed. These samples will be maintained at this preservation temperature and sent to their designated laboratory within 24 hours of collection and storage.

Analysis of the samples will be completed within the holding time listed in Table 25. As appropriate, alternative sample containers and preservation techniques approved by the UIC program director may be used to meet analytical requirements.

#### 4.3.1 B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 25 for maximum hold times for different samples.

#### 4.3.2 B.3.b. Sample Transportation

See beginning of section 4.3 for sample transportation details and standards.

#### 4.3.3 B.3.c. Sampling Documentation

Field notes will be collected for all groundwater samples that are collected. These forms and notes will be retained in archived. His reference sample documentation is the responsibility of the groundwater sampling personnel.

An analytical authorization form will be provided for each gas stream sample provided for analysis as shown by the example in Figure 4.

#### 4.3.4 B.3.d. Sample Identification

All sample bottles will have waterproof labels with the following information:

- Project name
- Sampling date
- Sampling location
- Sampling, identification number
- Sample type
- Analyte
- Volume
- Filtration used
- And preservative used

Figure 3 provides an example of such label.

**Table 24. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Groundwater Samples.**

<b>Target Parameters</b>	<b>Volume (Container Material)</b>	<b>Preservation Technique</b>	<b>Sample Holding Time</b>
<u>Cations:</u> Ca, Fe, K, Mg, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Tl	250 ml (HDPE)	Filtered, nitric acid, cool 4 °C	60 days
<u>Dissolved CO<sub>2</sub></u>	2 – 60 ml (HDPE)	Filtered, cool 4 °C	14 days
	60 ml (HDPE)	Filtered, cool 4 °C	14 days
<u>Isotopes:</u> <sup>3</sup> H, δD, δ <sup>18</sup> O, δ <sup>34</sup> S, δ <sup>13</sup> C	2 – 60 ml (HDPE)	Filtered, cool 4 °C	4 weeks
<u>Isotopes:</u> δ <sup>34</sup> S	250ml (HDPE)	Filtered, cool 4 °C	4 weeks
<u>Isotopes:</u> δD, δ <sup>18</sup> O, δ <sup>13</sup> C	60 ml (HDPE)	Filtered, cool 4 °C	4 weeks
<u>Alkalinity (anions):</u> Br, Cl, F, NO <sub>3</sub> , SO <sub>4</sub>	500 ml (HDPE)	Filtered, cool 4 °C	45 days
<u>Field Confirmation:</u> Temperature Dissolved Oxygen Specific Conductance pH	200 ml (glass jar)	None	<1 hour
<u>Field Confirmation:</u> Density	60 ml (HDPE)	Filtered	<1 hour

#### 4.3.5 B.3.e. Sample Chain-of-Custody

For gas stream analysis, an analysis authorization form provided (Figure 4) will accompany the sample to the lab, at which point this chain of custody form accompanies the sample throughout the analytical process.

For groundwater samples, chain of custody will be documented using a standard form. A typical form is shown in Figure 5. This form is similar to that which be used for all groundwater samples. Copies of the form will be provided to the person or lab receiving the samples, as well as the person or lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain of custody form and record keeping is the responsibility of the groundwater sampling personnel and all lab personnel involved in analysis.

#### **4.4 B.4. Analytical Methods**

Logging, geophysical monitoring, and pressure and temperature monitoring does not apply to this section and is, therefore, omitted.

##### **4.4.1 B.4.a. Analytical SOPs**

Analytical SPOs and their critical parameters are referenced in Tables 4 through 7. Other laboratory specific SOPs utilized by the contracted laboratories will be determined after such laboratory has been selected.

Upon request, OCP will provide the agency with all laboratory SOPs developed for the specific parameters, using the appropriate standardized method. Each laboratory technician conducting the analysis on these samples will be trained on the SOPs developed for each standardized method. OCP will include the technicians training certification(s) with the regular reports.

##### **4.4.2 B.4.b. Equipment/Instrumentation Needed**

Any equipment and instrumentation that is needed is specified in the individual analytical methods which are referenced in Tables 4 through 7.

##### **4.4.3 B.4.c. Method Performance Criteria**

It is not anticipated that any non standard method of performance criteria will be necessary for this project.

##### **4.4.4 B.4.d. Analytical Failure**

Each contracted laboratory conducting the analysis laid out in Tables 4 through 7 will be responsible for appropriately addressing any analytical failures according to their individual SOPs.

##### **4.4.5 B.4.e. Sample Disposal**

Each contracted laboratory conducting the analysis laid out in Tables 4 through 7 will be responsible for appropriate sample disposal according to their individual SOPs.

##### **4.4.6 B.4.f. Laboratory Turnaround**

Well, turn around. Time will vary by laboratory. It is generally anticipated that the turn around time of verified analytical results will be received within one month for project needs.

##### **4.4.7 B.4.g. Method Validation for Nonstandard Methods**

It is not anticipated that any nonstandard methods of validation will be necessary for this project. Should this change in the future, the EPA will be consulted on additional appropriate actions to be taken.

## 4.5 B.5. QC

Logging, geophysical monitoring, and pressure and temperature monitoring does not apply to this section and is, therefore, omitted. For logging QC, reference Appendix B.

### 4.5.1 B.5.a. QC activities

#### 4.5.1.1 *Blanks*

For shallow groundwater sampling, a field blank will be collected and analyzed for the inorganic analytes detailed in Tables 4 through 7 at a frequency of 10% or greater. It is noted that field blanks will be exposed to the same field and transportation conditions as the groundwater samples described in Section 4.4.

Blanks will also be utilized for deep groundwater sampling and analyzed for the same inorganic analytes detailed in Tables 4 through 7 at a frequency of 10% or greater.

Field blanks will be used to detect contamination, resulting from the collection and transportation processes.

#### 4.5.1.2 *Duplicates*

For shallow groundwater sampling, a duplicate groundwater sample will be collected from a well on a rotating schedule. Duplicate samples are collected from the same source of immediately after the original sample is taken. These samples will be kept in different storage containers and process the same as other samples. Duplicate samples are used to assess sample heterogeneity and analytical precision.

### 4.5.2 B.5.b. Exceeding Control Limits

If the analytical results exceed control limits, further examination of the analytical results will be done by evaluating the ratio of the measured TDS count to the calculated TDS count per the APHA method.

This method indicates which ion analysis should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and inter laboratory results if available. Suspect ion analyses are then brought to the attention of the analytical laboratory for confirmation and/or reanalysis.

The ion balance is then recalculated and if the error is still not resolved, suspect data are identified and may be given less importance and data interpretation.

### 4.5.3 B.5.c. Calculating Applicable QC Statistics

#### 4.5.3.1 *Charge Balance*

The analytical results are evaluated to determine the correctness of the applied analysis based on anion-cation charge balance calculation. Due to the fact that potable waters are electrically neutral, the chemical analysis should yield equally negative and positive ionic activity. The anion-cation charge balance is calculated using the following formula:

$$\% \text{ difference} = 100 \frac{\sum \text{cations} - \sum \text{anions}}{\sum \text{cations} + \sum \text{anions}}$$

Wherein the sums of the ions are represented in milliequivalents (meq) per L and the criteria for acceptable charge balance is  $\pm 10\%$ .

#### 4.5.3.2 *Mass Balance*

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the following formula:

$$1.0 < \frac{\text{measured TDS}}{\text{calculated TDS}} < 1.2$$

Wherein the anticipated values are between 1.0 and 1.2.

#### 4.5.3.3 Outliers

It is essential to determine the presence of any statistical outliers when performing evaluation and analytical analysis of groundwater. This project will utilize EPA's Unified guidance, published in March of 2009, as the basis for selection of recommended statistical methods to identify outliers and groundwater chemistry datasets as appropriate.

The techniques detailed in this documentation include:

- Probability plots
- Box plots
- Dixon's test
- Rosner's test

The EPA 1989 outlier test may also be used as an acceptable screening tool to identify any potential outliers within the data sets.

## 4.6 B.6. Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained and cared for, as is detailed in the wireline industry best practices provided in Appendix B.

Groundwater sampling field equipment will be maintained, serviced and calibrated per manufacturer recommendation. Spare parts that may be needed during sampling will be included and supplied during field sampling.

The contracted laboratories will be responsible to provide all testing, inspection, and maintenance of all laboratory equipment used for analytical purposes. Standard practice and method specific control should be followed during these activities.

## 4.7 B.7. Instrument/Equipment Calibration and Frequency

Geophysical monitoring does not apply to this section and is, therefore, omitted.

### 4.7.1 B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges as well as Flowmeter information is provided in Tables 12 through 22.

Logging tool calibration will be performed at the discretion of the contracted service company providing the equipment, assuming that it follows the standard industry practices noted in Appendix B. Further calibration frequency will be determined by standard industry practices.

For groundwater sampling, the portable field meters or multiprobe sondes that will be used to determine that field parameters are calibrated according to manufacturer recommendations and equipment manuals each day before sampling begins. Recalibration will be performed if any components yield atypical values or fail to stabilize during sampling.

### 4.7.2 B.7.b. Calibration Methodology

Logging tool calibration methods will follow standard industry practices laid out in Appendix B.

For groundwater sampling, the standards for calibration are typically as follows:

- For pH -7 to 10
- For specific conductance - potassium chloride solution yielding a value of 1413  $\mu\text{S}/\text{cm}$  at 25 °C
- For dissolved oxygen - a 100% dissolved  $\text{O}_2$  solution

Calibration is performed for the pH meters per manufacturer specification.

Coulometry instrumentation will be routinely evaluated using sodium carbonate standards.

#### 4.7.3 B.7.c. Calibration Resolution and Documentation

Logging tool, calibration, resolution and documentation will follow the standard industry practice as shown in the Appendix B.

For groundwater sampling tools, calibration values will be noted in daily sampling recordings, as well as errors in calibration, should there be any. For parameters where calibration is not acceptable, redundant equipment may be used to ensure that any potential loss of data is minimized.

### 4.8 B.8. Inspection/Acceptance for Supplies and Consumables

#### 4.8.1 B.8.a/b. Supplies, Consumables, and Responsibilities

As required by approved vendors, supplies and consumables for field and laboratory operations will be procured, inspected, and accepted as appropriate. Acquisition of such supplies and consumables related to groundwater analysis will be the responsibility of each laboratory per the established method or operating procedures.

### 4.9 B.9. Nondirect Measurements – Seismic Monitoring

#### 4.9.1 B.9.a. Data Sources

For timelapse seismic surveys, repeatability is paramount for accurate differential comparison. To ensure survey quality, the locations for the surface shots and acquisition method of sequential surveys must be consistent. Once these surveys have been conducted, they'll be compared to a baseline survey to track and monitor bloom development.

For Mt. Simon pressure monitoring downhole gauges in the OBS1 well will be used to gather pressure and temperature data.

#### 4.9.2 B.9.b. Relevance to Project

Seismic surveys will be used to track changes in the  $\text{CO}_2$  plume in the injection formation. Processing and comparing the subsequent surveys to the baseline survey taken before injection starts allows for the assessment and monitoring of plume growth. It will also help to ensure that the plume does not out grow outside of the intended reservoir. Additional modeling will be used to predict plume growth and migration overtime by combining the process seismic data and the existing geologic model.

The Mt. Simon monitoring data will also be used in this additional modeling to predict plume and pressure front behavior and to confirm the plume stays within the AoR.

#### 4.9.3 B.9.c. Acceptance Criteria

By following standard industry practices, it will be ensured that the gathered seismic data will be able to be used for accurate modeling and monitoring. Repeatable ground conditions, shoy point locationsm functional geophones, and similar seismic input data will be used from survey to survey to insure repeatability.

When processing this data, several quality assurance checks will be done in accordance with industry standards. Further detail on this industry standard methods of reformatting, structuring and application will be provided and further documents. Detail on these methods will be provided in the final Testing and Monitoring Plan (Attachment 7: Testing And Monitoring, 2022)

#### 4.9.4 B.9.d. Resources/Facilities Needed

OCP will provide all resources, equipment, and facilities needed for all seismic surveys. Seismic monitoring will be provided by a third part contractor. Downhole pressure monitoring will be performed in wells associated with the project. Groundwater sampling will be performed by a third part contractor.

#### 4.9.5 B.9.e. Validity Limits and Operating Conditions

Trained personnel will handle the review and analysis of all collected data to be used for the seismic surveys and numerical modeling. These checks will be done according to industry standard practices.

### **4.10 B.10. Data Management**

#### 4.10.1 B.10.a. Data Management Scheme

OCP or a designed third-party contractor will maintain the required data as provided elsewhere in the permit application. Data will be backed up digitally, or via hard copy as necessary

#### 4.10.2 B.10.b. Recordkeeping and Tracking Practices

All records and gathered data will be held securely and organized properly.

#### 4.10.3 B.10.c. Data Handling Equipment/Procedures

All equipment used to collect and store data will be properly maintained and operated according to industry standard practices. All supervisory control and data acquisition (SCADA) system(s) and other data acquisition system will interface with each other as necessary. All data will be held and stored securely.

#### 4.10.4 B.10.d. Responsibility

The primary project managers, as outlined in this document and in the permit application, will be responsible for ensuring the proper data management is maintained.

#### 4.10.5 B.10.e. Data Archival and Retrieval

All data will be held by OCP. These data will be maintained and stored for review as necessary as detailed in Section 4.10.1 above.

#### 4.10.6 B.10.f. Hardware and Software Configurations

All OCP and vendor hardware/software configurations will be interfaced appropriately.

#### 4.10.7 B.10.g. Checklists and Forms

All required checklists and forms will be generated and produced for usage, as necessary.

## **5 C. Assessment and Oversight**

### **5.1 C.1. Assessments and Response Actions**

#### **5.1.1 C.1.a. Activities to be Conducted**

Please refer to the Testing and Monitoring and PISC sections of the permit application to see the frequency of data collection for the activities listed in Table 1 of this document.

After completion of sample analysis and data collection, results will be QCed for the criteria as noted in Section 4.5 (QC) section of the QASP document. If the collected data and sample analysis are found to not be consistent with these standards of QC, they will be reanalyzed as detailed in the section. All evaluations of data consistency will be performed according to industry standard methods and those described in the EPA 2009 unified guidance.

#### **5.1.2 C.1.b. Responsibility for Conducting Assessments**

Third party organizations gathering and analyzing data will be responsible for conducting their own internal assessments.

#### **5.1.3 C.1.c. Assessment Reporting**

All assessment information should be reported to the individual project managers as outlined in this document.

#### **5.1.4 C.1.d. Corrective Action**

Corrective action that is taken to improve any individual organization's data collection responsibility should be addressed, verified, and documented by the project manager that the issue is reported to. After this, the individual project manager will communicate this information to the other project managers, as necessary.

Corrective actions that impact multiple organizations should be addressed by all members of the project leadership and communicated to the other members on the distribution list as outlined above for the QASP.

It is noted that the results of the corrective action may impact multiple sources of monitoring data/equipment and/or multiple organizations. It is, therefore, the responsibility of OCP to ensure the most cost-effective and efficient action is implemented across the project.

### **5.2 C.2. Reports to Management**

#### **5.2.1 C.2.a/b. QA status Reports**

It is currently anticipated that QA status reports will not be necessary. If any of the aforementioned testing or monitoring techniques are altered, the QASP will be reviewed and updated as necessary in consultation with the EPA. Revised QASPs will then be distributed to the full distribution list detailed at the beginning of this document.

## **6 D. Data Validation and Usability**

### **6.1 D.1. Data Review, Verification, and Validation**

#### **6.1.1 D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data**

Groundwater quality data validation will include the review of the following:

- Concentration units
- Sample holding times
- Review of duplicate Blank and other appropriate QA/QC results

All groundwater quality results will be entered into a database for periodic review and analysis.

Copies of this analysis and a laboratory analytical test results and or reports will be kept. In the regular periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general groundwater quality data and identify intra well variability.

After sufficient data has been collected, additional methods might be used to evaluate interwell variations for groundwater constituents and to evaluate if significant changes have occurred that could result in the leakage of CO<sub>2</sub> or brine beyond the intended reservoir.

### **6.2 D.2. Verification and Validation Methods**

#### **6.2.1 D.2.a. Data Verification and Validation Processes**

See Sections 6.1.1 and 4.5. Appropriate statistical software will be utilized to determine data consistency.

#### **6.2.2 D.2.b. Data Verification and Validation Responsibility**

OCP or the designated third party contractor will verify and validate groundwater sampling data.

#### **6.2.3 D.2.c. Issue Resolution Process and Responsibility**

OCP or the designated third party contractor will review the groundwater data handling management and assessment processes as necessary. Staff involved in these processes will consult with the Project Manager to determine if any actions are required to resolve issues.

#### **6.2.4 D.2.d. Checklist, Forms, and Calculations**

Checklists and forms will be developed specifically to meet permit requirements. These checklists or forms will be developed at a later date and provided as a part of regular reports, if necessary.

### **6.3 D.3. Reconciliation with User Requirements**

#### **6.3.1 D.3.a. Evaluation of Data Uncertainty**

The physical software will be used to determine groundwater data consistency using methods consistent with the EPA 2009 unified guidance documents.

#### **6.3.2 D.3.b. Data Limitations Reporting**

Data that is collected and evaluated will be presented using appropriate data-use limitations.

## 7 References

- (2022). *Attachment 1: Narrative*. Class VI Permit Application Narrative; Project Stampede, Vault 4401.
- (2022). *Attachment 10: ERP*. Emergency And Remedial Response Plan; Project Stampede, Vault 4401.
- (2022). *Attachment 11: QASP; Project Stampede*. Vault 4401.
- (2022). *Attachment 2: AOR and Corrective Action*. Area Of Review And Corrective Action Plan; Project Stampede, Vault 4401.
- (2022). *Attachment 3: Financial Responsibility*. Financial Responsibility; Project Stampede, Vault 4401.
- (2022). *Attachment 4: Well Construction*. Injection Well Construction Plan; Project Stampede, Vault 4401.
- (2022). *Attachment 5: Pre-Op Testing Program*. Pre-Operational Formation Testing Program; Project Stampede, Vault 401.
- (2022). *Attachment 6: Well Operations*. Well Operation Plan; Project Stampede, Vault 4401.
- (2022). *Attachment 7: Testing And Monitoring*. Testing And Monitoring Plan; Project Stampede, Vault 4401.
- (2022). *Attachment 8: Well Plugging*. Vault 4401.
- (2022). *Attachment 9: Post-Injection Site Care*. Post-Injection Site Care And Site Closure Plan; Project Stampede, Vault 4401.